TECHNICAL REVIEW DOCUMENT
for
RENEWAL / MODIFICATIONS TO OPERATING PERMIT 96OPAD120

Suncor Energy (USA), Inc. – Commerce City Refinery, Plants 1 and 3 (West Plant)
Adams County
Source ID 0010003

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SECTION I - PURPOSE

This document establishes the basis for decisions made regarding the applicable requirements, emission factors, monitoring plan and compliance status of emission units covered by the renewal and modifications of the Operating Permit for the Suncor Commerce City Refinery – Plants 1 and 3 (West Plant). The current Operating Permit for this facility was issued on August 1, 2004. The expiration date for the permit was August 1, 2009. However, since a timely and complete renewal application was submitted, under Colorado Regulation No. 3, Part C, Section IV.C all of the terms and conditions of the existing permit shall not expire until the renewal Operating Permit is issued and any previously extended permit shield continues in full force and operation. The source submitted a renewal application on August 1, 2008. Prior to and after submittal of the renewal application, the source submitted applications to modify their permit as indicated in the table below.

Date Received	Modification Type	Modification Description
10/16/06	Significant Mod	Incorporate provisions for CP 04AD0114 (T-774) and 04AD0115 (T-777).
12/15/06	Minor Mod	Clarify fuel gas monitoring language (Section II, Condition 59)
1/12/07	Administrative Amendment Minor Mod Significant Modification	Variety of Modifications – significant mod is primarily to incorporate 11 recently issued construction permits. Suncor refers to this as the "rainbow document".
4/18/07	Admin Amend	Dispensing of bio-diesel at the Tuck loading rack
7/2/07	Minor Mod	Revise VOC emission factor, remove SO_2 emission factor (use CEMS) and change PM_{10} emission factor for FCCU
9/10/07	Minor Mod	Replace Tank T-38
4/7/08	Minor Mod	Route East Plant desalter water into T-4501
6/17/08	Admin. Amend	Incorporate NO_X limits for FCCU
9/26/08	Minor Mod	New SVE unit (engine)
12/9/08	Minor Mod	T-778 and Boilers B-6 and B-8
2/10/09	Minor Mod	SVE thermal oxidizer
6/1/09	Minor Mod	Tank T-2010
10/8/09	Minor Mod	OMD piping jumper
10/15/09	Minor Mod	Catalytic Reforming Unit
2/11/10	Admin. Amend	T-4501 revise tank description
3/3/10	Minor Mod	Tank T-52
3/11/10	Minor Mod	H_2 Optimization Project
8/17/10	Minor Mod	Tank T7208
10/13/10	Not Specified	Rescind alternative monitoring plans
10/29/10	Minor Mod	Revise emission factors for main plant flare
11/1/10	Minor Mod	Request to rebuild tank T38
12/22/10	Minor Mod	D-133 and Wash Water Drum
4/5/11	Minor Mod	D-133 and Wash Water Drum

Date Received	Modification Type	Modification Description
5/13/11	Minor Mod	Groundwater Remediation Storage Tanks **Cancellation Request Submitted 6/20/12**
9/12/11	Minor Mod	FCCU NO_X and SO_2 Emission Limits
9/28/11	Minor Mod	H-16 and H-18 Emission Calculation Methodology
10/25/11	Minor Mod	Bio-diesel load-in at rail rack
2/7/12	Minor Mod	Centrifuge Generator Engine
4/23/12	Minor Mod	Centrifuge Control Device Engine

This document is designed for reference during review of the proposed permit by EPA and for future reference by the Division to aid in any additional permit modifications at this facility. The conclusions made in this report are based on the renewal application submitted on August 1, 2008 and the modification applications indicated in the above table, additional information submittals received on May 23, October 14 and November 15, 2011, January 25 and 30, February 27 and June 20, 2012, comments on the draft permit and technical review document received on August 5 and November 25, 2011, comments received on May 21, 2012 during the public comment period, previous inspection reports and various e-mail correspondence, as well as telephone conversations with the applicant. Please note that copies of the Technical Review Document for the original permit and any Technical Review Documents associated with subsequent modifications of the original Operating Permit may be found in the Division files as well as on the Division website at http://www.cdphe.state.co.us/ap/Titlev.html. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised construction permit.

SECTION II - DESCRIPTION OF SOURCE

This facility is classified as a petroleum refinery under Standard Industrial Code 2911. Plant 1 is the portion of the heritage Conoco facility located on the west side of Brighton Boulevard (formerly the West Plant) and Plant 3 is the portion of the heritage Conoco facility located on the east side of Brighton Boulevard (formerly the Asphalt Unit). The Plant 1 and 3 facilities form an integrated petroleum refinery producing a wide range of finished petroleum products, including gasoline, jet fuel, diesel fuel, fuel oil, LPG, vacuum residue and sulfur. Processes used at the facility include atmospheric and vacuum distillation, desalting, reforming, catalytic cracking, catalytic polymerization and hydrotreating. The facility processes both sweet and sour crude oils received via pipeline. Finished products primarily leave the refinery via rail and truck loading facilities.

The facility is located at 5801 Brighton Boulevard in Commerce City, CO. The Denver Metro Area, including Commerce City, is classified as attainment/maintenance for particulate matter less than 10 microns (PM_{10}) and carbon monoxide. Under that classification, all SIP-approved requirements for PM_{10} and CO will continue to apply in order to prevent backsliding under the provisions of Section 110(l) of the Federal Clean Air Act. The Denver Metro Area is classified as nonattainment for ozone and is part of the 8-hour Ozone Control Area as defined in Regulation No. 7, Section II.A.1.

There are no affected states within 50 miles of the plant. Rocky Mountain National Park and Eagles Nest National Wilderness Area, both Federal Class I designated areas, are within 100 kilometers of the plant.

The summary of emissions that was presented in the Technical Review Document for the original permit has been modified to reflect the updated potential to emit (PTE) of criteria pollutants due to changes that may have occurred in emission units, emission factors and/or emission limitations since the previous permit was issued and to reflect actual emissions. Emissions in (tons/yr) at the facility are as follows:

	Emissions (tons/yr)	
Pollutant	Potential To Emit	Actual Emissions
PM	138.15	90.87
$PM_{10}/PM_{2.5}$	138.15	90.87
SO_2	396.51	147.45
NO_X	692.69	331.55
CO	741.80	225.12
VOC	405.16	184.68

Detailed information on potential to emit (i.e., potential to emit by emission unit and method of estimated potential to emit) and actual emissions are shown on the tables on pages 82-86.

1. MACT Requirements

The facility is a major source for HAPs and as such the MACT requirements in 40 CFR Part 63 applies to specific equipment at the facility. The current permit includes the requirements from 40 CFR Part 63 Subpart R (National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)), 40 CFR Part 63 Subpart CC (National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries) and 40 CFR Part 63 Subpart UUU (National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units).

Since issuance of the current permit, the following MACT requirements have been determined to apply to equipment at the facility.

Site Remediation MACT (40 CFR Part 63 Subpart GGGGG)

In their renewal application, the source indicated that portions of the Site Remediation MACT apply to the truck rack and as a result the appropriate requirements have been included in the permit in Section II, new Condition 67. The remainder of the facility's site remediation is required by an order under RCRA section 7003 and is therefore exempt from the Site Remediation MACT requirements per 63.7881(b)(3).

RICE MACT (40 CFR Part 63 Subpart ZZZZ)

Final revisions to the RICE MACT were published in the Federal Register on March 3, 2010 and August 20, 2010. The March 3, 2010 revisions address existing (commenced construction prior to June 12, 2006) compression ignition engines $\leq$ 500 hp and existing (commenced construction prior to December 19, 2002) non-emergency compression ignition engines located at major sources. The August 20, 2010 revisions address existing (commenced construction prior to June 12, 2006) spark ignition engines $\leq$ 500 hp at major sources. The insignificant activity list indicates that there are miscellaneous diesel-driven plant equipment. Many of the engines qualify as non-road engines and as such are not considered stationary sources and are not subject to the RICE MACT requirements. However, Suncor submitted information on October 14, 2011 indicating that three engines do not qualify as non-road engines and are subject to RICE MACT requirements. These engines are emergency fire pump engines and are subject to work practice standards. The appropriate applicable requirements for these engines have been included in the permit.

Industrial, Commercial and Institutional Boilers and Process Heaters MACT (40 CFR Part 63 Subpart DDDDD)

The final rule for industrial, commercial and institutional boilers and process heaters was published in the Federal Register on September 13, 2004. Under 40 CFR Part 63 Subpart DDDDD most of the boilers and process heaters were not subject to any substantive requirements (existing units $\leq$ 10 MMBtu/hr were not subject to any requirements and existing units > 10 MMBtu/hr were only subject to the initial notification requirements). However, the Boiler MACT was vacated July 30, 2007. Due to the vacatur, EPA was required to re-promulgate requirements for this source category.

Final Boiler MACT requirements were published in the Federal Register on March 21, 2011. The final rule does not include emission limits for natural gas or refinery gas fired units but instead specifies work practice requirements. Sources will be required to conduct tune-ups on new and existing units (annual for units that are greater than or equal to 10 MMBtu/hr and biennial for units that are less than 10 MMBtu/hr). The appropriate applicable requirements have been included in Section II, Condition 64 of the permit. It should be noted that proposed revisions to the Boiler MACT were published in the Federal Register on December 23, 2011. Based on a review of the proposed rule it does not appear that the requirements will change much, if at all, for the emission units at this facility but a note was added to Condition 64 to indicate that the requirements may change in the future when the rule is finalized.

2. Compliance Assurance Monitoring (CAM) Requirements

CAM applies to any emission unit that is subject to an emission limitation, uses a control device to achieve compliance with that emission limitation and has potential pre-control emissions greater than major source levels. In their August 1, 2008 renewal application, the source indicated that the CAM requirements applied to the FCCU with respect to the PM emission limitation. CAM is addressed in greater detail under the discussion on the renewal application (see Section III.1.8 of this document).

3. Greenhouse Gases

Greenhouse gas (GHG) emissions from the Commerce City Refinery exceed 100,000 tpy CO_2e. Future modifications at the refinery will have to be evaluated to determine if GHG emissions are subject to regulation.

SECTION III - DISCUSSION OF MODIFICATIONS MADE

The following discussion related to modifications is with respect to the current Title V permit (last revised December 18, 2006) and unless specifically noted as “new”, the condition numbers identified in this document reflect the condition numbers in the current (December 18, 2006) Title V permit. Because some permit conditions in the current Title V permit have been removed, reorganized and/or reformatted as part of this permitting process, the condition numbers discussed in this document may not reflect the condition numbers in the draft Title V permit.

1. Source Requested Modifications

The source’s requested modifications were addressed as follows:

1.1 October 16, 2006 Modification (minor modification) – Tanks T774 and T777

The purpose of this modification was to incorporate construction permits 04AD0114 (T-774) and 04AD0115 (T-777) into the Title V permit. The following changes were made to the permit.

Section I – Condition 1.4 – added construction permit numbers 04AD0114 and 04AD0115 to the list.

Section I, Condition 5.1 (table), Appendices B and C – added tanks T774 and T777 to the tables.

Section II.4 – Added the tanks (emission and throughput limits) to the table and noted the applicable MACT and RACT requirements for each tank.

Section II, Condition 41.2.3 – added T777 to the list as subject to the requirements and noted that T774 was only subject to recordkeeping requirements.

Appendix A – remove tank T777 from the insignificant activity list.

1.2 December 15, 2006 Modification (minor modification) – Fuel Gas Monitoring Language (Section II, Condition 59)

The purpose of this modification was to clarify the fuel gas monitoring language (Section II, Condition 59). The following changes were made to the permit.

Section II, Condition 59 – the change was made as requested.

1.3 January 12, 2007 Modification – Rainbow Document

The primary purpose of this modification was to incorporate the requirements for several new and constructed emission units that were addressed under construction permits. In addition, various corrections and minor changes to existing language were requested. The modification identified significant and minor modifications, as well as administrative amendments. Changes were made to the permit, as follows:

1.3.1 Significant Modifications

Section I, Condition 1.4 – updated the list of construction permit numbers to include the new construction permits issued for the Clean Fuels Project.

Section I, Condition 5.1 – revised the table to include the new emission units installed as part of the Clean Fuels Project. Removed the component list for points F102 and F103 – the Division considers that as long as the emission limits are met, the number of components do not need to be specified.

General – Although not specifically noted in the cover letter for the significant modifications, the marked up version of the permit indicates requested changes to the permit to address the Industrial, Commercial, Institutional Boiler and Process Heater MACT (40 CFR Part 63 Subpart DDDDD). As of July 30, 2007, the Boiler MACT was vacated; therefore, the provisions in 40 CFR Part 63 Subpart DDDDD are no longer in effect and enforceable. Final Boiler MACT requirements were published in the Federal Register on March 21, 2011. The appropriate applicable requirements from Boiler MACT are included in Section II, Condition 64 of the permit. As noted previously, proposed revisions to the rule have been published, so a note was added indicating the requirements may change once the rule is finalized.

In addition, the effective dates for the MACT standards were removed from the tables, since these dates have passed.

Section II.20 and 21 – added an additional equation to the emission calculation condition (Conditions 20.1 and 21.1).

Section II.23 – This Condition was revised to address the tail gas unit (TGU) and incinerator that were installed for SRU #1 and #2. The TGU was addressed in Construction Permit 04AD0111 (issued May 24, 2004) and the appropriate provisions from that permit were included in the operating permit. The following issues warrant additional discussion related to incorporating the construction permit conditions.

- The construction permit includes a requirement that RACT has been determined to be operation of the tail gas processing unit with an efficiency of 95.5%. The short term and annual SO_2 emission limits were set based on an assumed tail gas unit control efficiency of 95.5%. The current Title V permit includes the 95.5% control efficiency for the SRU #2/tail gas unit and compliance with the 95.5% control efficiency is presumed provided the outlet emission limitations are met. Since only outlet SO_2 emissions are monitored from the SRUs, a RACT limit based on outlet SO_2 emissions is more appropriate than a percent reduction RACT limit. Therefore, the RACT requirements have been revised to specify that RACT is operation of the tail gas processing unit to meet the short term and annual outlet SO_2 emission limitations.

- The source requested that the short-term (lb/hr) SO_2 emission limit not be included in the Title V permit. In their application, the source indicated that during the initial analysis impacts were below the significant impact level (SIL), therefore, short-term SO_2 emission limits are not necessary. However, the Division considers that since impacts were very close to the SIL for the 24-hr standard (4.7 $\mu g/m^3$ vs 5 $\mu g/m^3$), because impacts were below the SIL and the source avoided a cumulative impact analysis, that short term SO_2 limits are necessary. In addition, although there is a limit on the H_2S content of the refinery fuel gas (which limits SO_2 emissions from the combustion of these gases), this limit does not apply to waste gases processed by the TGU; therefore, the lbs/hr SO_2 limit is necessary.

- Although the fugitive emissions from components associated with the amine treatment system are addressed in this construction permit (04AD111), they are addressed in Section II.34 of this permit. Note that although the permit lists a specific number of components, a limit on the number of components has not been included in the Title V permit.

In addition, Section II.23 was revised to remove the "interim measures" (Condition 23.7) and the NSPS J compliance date (Condition 23.6) set forth in the Consent Decree for the SRU.

In addition in Section II.23, the Reg 1 PM emission limitation for incinerators was revised (Condition 23.10) to include the PM limit for nonattainment and attainment/maintenance areas and to remove the requirement to obtain a permit (a permit was issued for the incinerator, therefore, this requirement has been completed and need not be included in the permit).

Although not specifically noted in the construction permit, in addition to the Reg 1 incinerator requirements, the TGU incinerator is also subject to the incinerator requirements in Regulation No. 6, Part B, Section VII, which are state-only standards. The Reg 6, Part B, Section VII requirements include particulate matter standards and specific requirements for monitoring and test methods. However, the Division's policy memo PS 99-2, dated May 6, 1999 (see attached), indicates that since these particulate matter standards are based on the charging rate, which is specified in tons/yr, the Division considers that these standards were not intended to apply to flares that were only burning waste gases, since a tons/yr charge rate is not practical for that type of incinerator. Since the particulate matter standards do not apply, the Division considers that the monitoring and testing requirement also do not apply. Therefore, the only relevant requirement that applies is the 20% opacity requirement. Section II, Condition 35.4 was revised to indicate that in addition to Section II.C.2, that the state-only 20% opacity is also from Section VII.C – but only for the TGU incinerator (H-25).

<u>"New" Section II.21</u> – revised to include the requirements for process heaters H1716 and H1717 (Section II.21 in the current permit addresses Heaters H-33 and H-37). Heaters H1716 and H1717 are addressed in Construction Permit 04AD0110 (issued May 24, 2004) and the appropriate provisions from that permit were included in the operating permit. The following issues warrant additional discussion related to incorporating the construction permit conditions.

- Although the fugitive emissions from components associated with the No. 4 HDS system are address in this construction permit (04AD110), they are addressed in Section II.34 of this permit. Note that although the permit lists a specific number of components, a limit on the number of components has not been included in the Title V permit.

- The short-term (lb/hr) SO_2 limit was not included in the permit. As discussed above under Section II.23, the Division considers that a short-term SO_2 limit is necessary since impacts in the original analysis were very close to the SIL. However, these heaters are subject to a fuel sulfur limit which is based on a 3-hr average and the lbs/hr SO_2 limit is based on that fuel sulfur limit and the design rate of the units. Therefore, the Division considers that the lbs/hr limit is not necessary.

A revised construction permit was issued for these heaters on December 30, 2010. The revised construction permit addresses modifications to the heaters to increase the design heat input rate. The revised construction permit includes revised emission limitations and throughput limits for the heaters, as well as revised emission limits for fugitive VOC emissions from the new components associated with the modification. The provisions from the December 30, 2010 permit have been included in the draft renewal permit. It should be noted that the modification renders that heaters subject to the provisions in NSPS Subpart Ja (and no longer subject to the provisions in NSPS Subpart J). Since the provisions in NSPS Ja for fuel gas combustion devices have been stayed, it is not clear exactly what requirements these heaters will be subject to. However, the construction permit includes a requirement for the H_2S content of the fuel gas that is consistent with the NSPS J requirement in order to have an enforceable short term SO_2 emission rate (as discussed above the short term fuel sulfur requirements limits short term SO_2 emissions). The NSPS Ja requirements will be included in "New" Section II.46 of the permit when they are promulgated (Section II.46 of the current permit addresses Subpart J and Flaring).

Section II.29 – Construction permit 88AD388 was revised (June 30, 2006) to reduce the frequency of monitoring. These revised monitoring requirements were included in the permit, with the exception that the time between monitoring contamination concentrations has been revised to 10 days between monthly samples.

"New" Section II.27 – revised to include the requirements for the hydrogen plant furnace H-2101 (Section II.27 of the current permit addresses the rail rack flare). The hydrogen plant furnace is addressed in Construction Permit 04AD0109 (issued May 24, 2004) and the appropriate provisions from that permit were included in the operating permit.

Section II.34 – revised to include the requirements for fugitive emission sources in Construction Permits 04AD0111 and 04AD0110 and the requirements in Construction Permits 04AD0112 and 04AD0113 and revised Construction Permits 91AD180-1, 91AD180-4 and 91AD180-2 (all new or revised permits issued May 24, 2004). The appropriate provisions from the construction permits were included in the operating permit. The following issues warrant additional discussion related to incorporating the construction permit conditions.

- The source requested that the number of components that are listed in the construction permits be removed and they have been. It has been the Division's current practice to not include numbers and types of components as limitations in the permit.

- The source also requested that the emission limitations no longer be enforced and has requested that they be removed from the permit. While the Division has not included component counts in the operating permit, the emission limitations are still enforceable. The current permit specifies that rolling twelve month totals be retained to monitor compliance with the annual limitations and specifies that compliance with the emission limits is presumed if the LDAR requirements are met. The Division does not think that it is appropriate to specify that compliance with the emission limits is based strictly on meeting the LDAR requirements, as failure to conduct the required monitoring might then appear to be an indication of a violation of the emission limitations. The Division has revised the permit to specify that emission calculations be performed annually to monitor compliance with the permitted emission limitations.

- Construction Permits 04AD0110 and 04AD0112 specify levels for leaks (i.e. 500 ppmv for valves and 2,000 ppmv for pumps). These definitions were included because the source relied on a higher control efficiency utilized for sources that have an LDAR program consistent with the HON MACT. The permit did not specify how leaks would be monitored.

Section II.35 and 58 – the source requested that the frequency of opacity monitoring for SRU 1 and 2 (TGU and incinerator) and the main plant flare be revised. The source specifically requested that for SRU 1 and 2 (TGU/incinerator) that the frequency be revised from twice per day visible observations (not method 9) and semi-annual method 9s to quarterly method 9s. For the main plant flare, the source requested that the opacity monitoring be revised from daily visible observations (not method 9) to quarterly method 9s.

With respect to SRU 1 and 2 (TGU and incinerator), the Division agrees that less frequent monitoring for opacity is appropriate. However, the Division considers that monthly visible emission checks, in conjunction with quarterly method 9s represents more appropriate monitoring for these sources. Note that the permit specifies that the quarterly method 9 can fulfill the requirements for the monthly visible emission check for that particular month. In addition, the Division removed the language the parenthetical phrase "during daylight hours".

In addition, the Division considers that daily visible emission observations for the main plant flares are still appropriate; therefore, the frequency of monitoring has not been revised. However, the Division has revised the language to indicate that daily observations are only required on the main plant flare when gases other than pilot gases are routed to the flare.

Appendices B and C – revised tables to include new emission units installed as part of the Clean Fuels Project.

1.3.2 Minor Modifications

Section I, Condition 5.1 – removed the air sparge/soil vent system from this table since the unit has been removed from service.

Section II.3 – the source requested that the emission limits for Tank T775 and the reid vapor pressure limit for this tank be increased. However, it appears that this change was reflected in the December 18, 2006 revised permit, therefore, no changes are necessary.

Section II.18 – the source requested that the PM, PM_{10} and CO emission limits for heater H-19 be revised to reflect the revised AP-42 emission factors and the permitted fuel consumption limit. The change was made as requested.

Section II.21 – the source requested that the NO_X emission limits for heaters H-33 and H-37 be increased to reflect the AP-42 emission factors and the permitted fuel consumption limit.

During a file review, the Division discovered that errors were made in processing the

May 7, 2002 application to revise the underlying construction permit (91AD180-2) for these heaters. While the Division revised the NO_X limit as requested, the NO_X emission factors were not appropriately identified in the construction permit. In the May 7, 2002 application, the emission factors used for H-37 were AP-42 factors (100 lb/MMscf) and were 0.035 lb/MMBtu for H-33. The revised construction permit (issued May 24, 2004), retained the previous emission factor for H-37 (0.12 lb/MMBtu) and didn't identify the lower emission factor for H-33. In their comments on the draft permit (submitted August 5, 2011), the source indicated that the emission factor included in the current permit for T-33 was based on performance test results. Therefore, the Division corrected the emission factor for H-37 and adjusted the NO_X emission limit to correspond to the emission factors and fuel consumption limits. The NO_X emission limit was revised to 26.3 tons/yr.

Section II.30 – removed the requirements for the air sparge/soil vent system (note that in order to preserve numbering a new emission unit is included in Section II.30).

Section II.38:

The source requested that the Reg 1 SO_2 requirements for new refineries be included in Condition 38.1 (currently the Reg 1 SO_2 requirement for existing refineries is included in this condition). The Division and Suncor have agreed that based on the extent of past modifications, the facility is considered to be a "new" refinery for purposes of this Reg 1 requirement. Note that the Division did not include the source's suggested language for Condition 38.1 (Reg 1 requirement for new refineries).

In addition, the source requested that the Reg 6, Part B SO_2 state-only requirement for new refineries be included in the permit (the Division and Suncor agreed that the refinery should be considered "new" for purposes of this Reg 6, Part B requirement). Given that the Reg 1 and Reg 6, Part B limits are similar (0.3 lbs SO_2/barrel) the Division considered whether it might be appropriate to streamline the Reg 6, Part B requirement. The SO_2 requirements in both Reg 1 and Reg 6, Part B are numerically the same standard. The Regulation No. 6, Part B requirement is a state-only requirement. The averaging time is specific for the Reg 1 limitation (the standard is 0.3 lbs/barrel/day), while the averaging time for the Reg 6, Part B standard is not specified. Generally the Reg 6, Part B requirements for SO_2 (e.g. Section II and IV) are essentially the same numerically as the Reg 1, Section VI.B SO_2 requirements for new sources, although in general the averaging times are unspecified for the Reg 6, Part B requirements. Although Reg 6, Part B requirements incorporate the NSPS general provisions, which include performance test requirements. The performance test requirements in the NSPS general provisions, specify that test will consist of three test runs, but the duration is not specified (defers to specific subpart). Therefore, there is no clear indication in the regulation as to how compliance with the Reg 6, Part B limit shall be monitored. In practice the Division has required that the source estimate daily SO_2 emissions and then divide daily emissions by the daily average of barrels processed for the month (Reg 1) or calendar year (Reg 6, Part B). Therefore, in practice, the Reg 6, Part B limit is less stringent than the Reg 1 limit (longer averaging time for daily barrels), therefore, the Reg 6, Part B limit will be streamlined out in favor of the Reg 1 limit. Reg

6, Part B will be identified in Section III.3 of the permit as a streamlined condition.

Section II, multiple locations - related to the above change, the various other sections of the permit that include the existing Reg 1 SO_2 limit for existing refineries have been revised to include the Reg 1 SO_2 limit for new refineries.

Section II.59 – the source requested a change to the fuel gas monitoring language. This change was already made as requested under the December 15, 2006 modification.

Section III.1, Permit Shield for Non-Applicable requirements – the source requested that the reference to Colorado Regulation No. 6, Part B, Section IV.C.2 be removed. As discussed previously, the Division has streamlined the Reg 6, Part B SO_2 limit for refineries in favor of the Reg 1 limit; therefore, the Reg 6 Part B SO_2 limit is included in the permit shield for streamlined conditions (Section III.3 of the permit).

Appendices B and C – removed the air sparge/soil vent system from the tables.

1.3.3 Administrative Amendments

Cover Page and Headers – this modification requests that the permit be revised to indicate the date it was last revised. The Division will update the permit with the date the permit was last revised upon issuance. Note that the “last revised date” indicated in the permit is the date the revised permit is issued.

Page following cover page – the responsible official and the title for the permit contact will be revised as requested.

Section I, Condition 3 – added a condition to indicate that there is another operating permit to be considered for prevention of significant deterioration (PSD) and nonattainment area new source review (NANSR) purposes.

Section II, Condition 6 – increased the throughput limit in Condition 6.8 (text). Source had previously requested the increase in throughput but the increase was only reflected in the summary table, not the text.

Section II, Conditions 27 and 28 – removed the reference to AP-42 Section 5.2 flare emission factors for VOC emissions (summary tables, Conditions 27.1 and 28.1). VOC emissions are based on loading emission factors.

Section II, Condition 31.1 – corrected the units from “mmbbl” to “mbbl” in the equation.

Section II, Condition 33 – corrected the references in the summary table for the RACT and NSPS conditions. In addition, included the reference for VOC emissions in the summary table (condition 33.1) and the reference to RACT conditions (text, condition 33.3).

Appendix A – added language to the directions as requested.

1.4 April 18, 2007 Modification (administrative amendment) – Dispensing Bio-Diesel at Truck Rack

The purpose of this modification was to modify the truck loading rack to allow for dispensing bio-diesel blended fuels. The source did not request an increase in emissions or throughput for the truck loading rack (permitted VOC emissions are at 29 tpy), nor are changes in throughput needed (permit allows transfer of petroleum distillates that have a TVP $\leq$ 0.029 psi at 100 º F). The bio-additives will be added to the diesel stream in the diesel loading arm, before it reaches the truck (blending is done in the rack), so bio-diesel is unloaded, not bio-additives. Since bio-diesel is primarily diesel fuel (with some percentage < 20% of bio-additives), the description "petroleum distillates" adequately covers bio-diesel. In a letter dated May 17, 2007, the Division informed the source that the only permit modification necessary for this project was to include the bio-additive tanks to the insignificant activity list and that the modification could be processed as an administrative amendment. The April 18, 2007 application indicated that two tanks would be installed; however, in their comments on the draft permit (submitted on August 5, 2011), Suncor indicated that only one tank was installed. The following changes were made to the permit.

Section II.28 –as previously stated the description "petroleum distillates" adequately covers bio-diesel. However, for clarity the Division added "bio-diesel" to the language in parenthesis in Condition 28.5.

Appendix A – added the bio-additive storage tank to the insignificant activity list (T8103, 15,000 gal).

1.5 July 2, 2007 Modification (minor modification) – FCCU Emission Factors

The purpose of this modification is to revise the PM, VOC and SO_2 emission factors for the FCCU. According to the technical review document (TRD) prepared for the original Title V permit, the emission factors for PM, VOC and SO_2 were from AP-42, however, it is not clear which version or whether these factors are some revised version of AP-42 factors, since only the VOC emission factor is consistent with AP-42, Section 5.1 (dated 1/95), Table 5.1-1 (uncontrolled FCCUs). The source's proposed modification is to revise the PM and PM_{10} emission factors to the NSPS Subpart J PM limit, revise the VOC emission factors to the factor included in the Plant 2 Title V permit and to rely on the SO_2 CEMS (note that in the text of the permit, it requires the use of the SO_2 CEMS but in the table an emission factor is listed). Note that in accordance with the source's application, the Plant 2 VOC FCCU emission factor is based on performance tests conducted in 2001 and per the TRD prepared for the original Plant 2 Title V permit, the emission factor is based on performance testing conducted in February 2002. Based on the August 5, 2011 comments on the draft permit, it is clear that the Plant 2 VOC emission factor was the result of performance tests conducted in February 2001. The following changes were made to the permit.

<u>Section II.25</u> – revised the PM, VOC and SO_2 emission factors in the table under Condition 25.1 as requested and indicated in the text portion for Condition 25.1 the source of the emission factors. In addition, since the PM emission factor is based on the coke burn off, a new condition was added to require that that the coke burn off rate (lbs) be recorded daily to calculate annual emissions. Although this unit is not subject to annual emission limits for PM and PM_{10}, the daily recording of coke burn-off is required by NSPS Subpart J.

1.6 April 7, 2008 (minor modification) – Tank T4501

The purpose of this modification is to route desalter water from Plant 2 (east plant) to the Plant 1 desalter tank (T-4501). Tank T-4501 is used to promote the separation of water/oil effluent from the Plant 1 desalters. This project will also increase the throughput of oil to tank T-58, which receives the oil phase from T-4501. Tank T58 is currently a grandfathered tank (i.e. not subject to emission or throughput limitations. Tank T-4501 will also operate as a refinery slop tank, receiving recovered oil from vacuum trucks, the Plant 2 API separators and the tank farm sump system. Material stored in Tank T-4501 is at an elevated temperature (~ 120 ºF). Since EPA TANKS program relies on storage at ambient temperature, the TANKS model run is based on storage of a material with a higher RVP (~12), than the material that will actually be stored (RVP 7), to account for the higher temperature. The source requested increased emission and throughput limits for both tanks T-58 and T-4501. This modification does not change the applicable requirements, such as Reg 7 and NSPS that are previously addressed in the permit for these tanks. It should be noted that the source indicated in the application that tank T-58 is already subject to the requirements in NSPS Kb, but it is not (according to information available to the Division the tank became operational in 1957). Although tank T-58 may receive more petroleum liquids, the capacity of the tank will not be changed and so the Division does not consider that tank T-58 has been modified for purposes of NSPS applicability. However, the application does note that Tank T-4501 is subject to the requirements in 40 CFR Part 61 Subpart FF, “National Emission Standards for Benzene Waste Operations” (BWON), which are not included in the permit. These requirements will be addressed later in this document.

In addition, the source estimated VOC emissions from new components to be 0.94 tons/yr. New components to be installed (light liquid service) are 1 new pump, 24 connectors and 8 valves. No APEN was submitted for the fugitive VOC emissions from new components. Since emissions from the new components are less than the APEN de minimis level of 1 tpy VOC, these emissions shall be reported on the plantwide fugitive VOC APEN (for components without permit limits).

Emissions related to this project are as follows:

	VOC Emissions (tons/yr)		
Emission Unit	Requested	Change in Permitted	Change in Actual*
T-4501	6.68	3.93	5.89
T-58	4.17	4.17**	3.12

	VOC Emissions (tons/yr)		
Emission Unit	Requested	Change in Permitted	Change in Actual*
Fugitive Emissions from Equipment Leaks	0.94	0.94	0.94
Total	11.79	9.04	9.95

*Change in actual emissions for T-4501 and T-58 are based on requested emissions minus average of previous two years of actual emissions (3/06 thru 2/08). Change in actual for fugitive emissions are based on requested, since these are new components (actual emissions = 0).
**tank T-58 was grandfathered (not subject to permit limits), value shown is requested emissions.

A second modification was submitted for tank T4501 on February 11, 2010, which is discussed in detail later in this document. In that modification, the source requested only that the permit be revised to indicate that the tank would be storing slop oil and that no throughput or emission increases were necessary. Therefore, the emission and throughput increases associated with tank T-4501 in this modification were not made in the draft permit. However, the requested changes in emission and throughput limits for tank T58 were made.

The following changes were made to the permit.

Sections II.1 and 3 – removed tank T-58 from Section II.1 and included in Section II.3, with the appropriate emission, throughput and content limitations (RVP less than 7 psia).

1.7 September 12, 2011 and June 17, 2008 Modifications (minor modification and administrative amendment) – FCCU NO_X and SO_2 Limits

Under the terms of the Consent Decree, Suncor was required to optimize NO_X and SO_2 reducing catalyst additives in the FCCU and request NO_X and SO_2 emission limitations. The source has completed this process and on June 17, 2008 Suncor submitted an administrative amendment to include NO_X and SO_2 emission limitations for the FCCU based on the optimization process. Section II, Condition 61.1 of the permit indicates that incorporation of emission limits established by the Consent Decree can be incorporated into the Title V permit as an administrative amendment.

The proposed NO_X limits in the June 17, 2008 modification application were 99 ppmvd on a 7-day average and 74 ppmvd on a 365-day rolling average and the proposed SO_2 limits were 50 ppmvd on a 7-day rolling average and 25 ppmvd on a 365-day rolling average. However, following a January 2010 conference call with EPA, on February 12, 2010 Suncor proposed lower NO_X limits to EPA. Suncor submitted a minor modification application on September 12, 2011 to request the lower NO_X emission limitations on the FCCU (the modification application also requested SO_2 emission limits but these limits are the same as those requested in June 17, 2008 application). These lower NO_X limits of 86.8 ppmvd on a 7-day rolling average and 58.7 ppmvd on a 365-day rolling average have been included in the permit.

The following changes were made to the permit based on these modification applications.

Section II.25 – revised Condition 25.7 to include the NO_X limits and removed Conditions 25.7.1 through 25.7.3 since they are no longer necessary. Revised Condition 25.12 to include the SO_2 limits and removed Conditions 25.12.1 through 25.12.3.

1.8 August 1, 2008 Renewal Application

The renewal application includes a number of changes; therefore not all changes are listed here. Suncor specifically notes the following changes in the cover letter for the application, these include the following:

- Removing entries to tanks T-20 and T-21 and their associated flare and heaters H-8 and H-12

  The Division removed references to this equipment in the tables in Section I, Conditions 5.1 and Appendices B and C. In addition, references were removed from Section II.3 (T-20, T-21 and associated flare) and Section II.9 (H-8 and H-12), as well as other references to this equipment throughout the permit.

- Numbering all paragraphs.

  In the renewal application Suncor indicated a desire to number all paragraphs. Additional numbering was added to the draft permit and Suncor indicated in their August 5, 2011 comments on the draft permit that the numbering was acceptable.

- Including a number of storage tanks that were previously in the insignificant activity list (Appendix A) as significant emission units in Section II of the permit.

  Many of the tanks included in the insignificant activity list in the current permit are subject to MACT requirements (40 CFR Part 63 Subpart CC), they cannot be considered insignificant activities as specified in Colorado Regulation No. II.E. The tanks (approximately 30) were included in the appropriate sections of the permit.

  Note that in their August 5, 2011 comments on the draft permit and technical review document, Suncor indicated that five tanks should be removed from the draft permit (T164, T169, T170, T171 and T172) and corrected the size and contents of other tanks.

- Including specific requirements that have only previously been referenced in the permit (e.g. 40 CFR Part 60 Subpart VV)

  The requirements for NSPS Subpart VV were included in Section II, Condition 65.

- A Compliance assurance monitoring (CAM) plan was submitted for the FCCU for the NSPS Subpart J particulate matter emission limitation.

  Further discussion on CAM is addressed later in this document.

- Formatting errors for Conditions 3.1, 29.1, 33.1, 34.1, 35.1 38.1 and 43.1 (they appear as “Condition 0”)

These formatting errors have been corrected.

- Including a figure for a “new” appendix to identify those areas that are subject to the provisions of 40 CFR Part 63 Subpart GGGGG (site remediation MACT).

  The figure was added to Appendix I of the permit.

- Requests for modifications submitted prior to the renewal application are included in the renewal application.

  Modification applications submitted prior to the renewal application were addressed as noted in this document.

Some of the more noteworthy changes requested in the renewal application are addressed below:

Suncor has requested that some requirements that have been completed or that don’t apply be removed from the permit. These requirements are as follows:

Consent Decree Requirements (various sections):

- As requested by the source in the renewal application, the following requirements were removed because they have been completed:
  - Section II.22: 22.1.2, 22.1.4, 22.1.5, 22.1.8, 22.1.11 and 22.2.1
  - Section II.25: 25.7.1 through 25.7.3 and 25.12.1 through 25.12.3
  - Section II.46: 46.2.1, 46.2.3, 46.2.4, 46.3.4.1 through 46.3.4.4 and 46.6.

Sections II.27 and 50

- Suncor requested that the NSPS requirements for the rail rack be clarified in the permit (Section II.27) to specifically note that the requirements in NSPS XX are achieved through compliance with 40 CFR Part 63 Subpart CC. However, upon review, the Division determined that the NSPS XX requirements do not apply to the rail rack, since they are only applicable to “loading racks at a bulk gasoline terminal which deliver liquid product into gasoline tank trucks”. Since the loading rack loads into rail cars, NSPS XX does not apply. Therefore, Condition 27.9 which indicated that NSPS XX applies to the rail rack was removed from the permit.
- The source requested that the provisions in Conditions 50.5 and 50.11 be revised to appropriately indicate the compliance obligations for the rail rack. The Division did not make the changes requested but instead indicated in the introductory section of Condition 50 that the requirements in Subpart XX do not directly apply to the rail rack.
- Both the rail rack and the truck rack are equipped with flares as defined in 60.501. In accordance with the provisions in 60.503(e), the performance tests in 60.503(c) do not apply to flares. It is not clear in Condition 50.11 which test

methods are to be conducted every five years. For Title V permits, the Division has typically required that testing be repeated every five years as periodic monitoring for NSPS requirements, since the NSPS generally only required a one-time test. However, in this case the source is exempt from testing as long as the flare is in compliance with 60.18(b) through (f). Therefore, the requirements in Condition 50.11 were replaced with the language in 60.502(f).

Section II.43

- The source requested that the monitoring (daily walk through) in Condition 43.1.2 (Reg 7, Section VIII.A.2 requirements for wastewater (oil/water) separators) be revised to be more consistent with the requirements in 40 CFR Part 61 Subpart FF and 40 CFR Part 60 Subpart QQQ. The Division has revised this condition in part, as requested by the source; however, the revised language requires monthly visual inspections.
- In addition, although not requested by the source, the Division revised the daily walkthrough requirement in Condition 43.5 to monthly.

Section II.45

- The source requested that Condition 45.3 (NSPS J options for SO_2 standards for FCCU) be revised to indicate which option the source was following. The source indicated that they would be complying with the emission limit for FCCU's without add-on control devices (20 lb/ton coke burn-off). However, the source has also proposed SO_2 limits for the FCCU as required by the Consent Decree. One of these requested limits (50 ppmvd @ 0% O_2 on a 7-day rolling average basis) is the same as the SO_2 limit in NSPS J for FCCUs with add-on controls. Therefore, since the FCCU is subject to an SO_2 limit under the Consent Decree that is a compliance option under NSPS J, the NSPS J SO_2 limit has been streamlined in favor of the Consent Decree limit. The NSPS J SO_2 limit and monitoring requirements have been included in the permit shield for streamlined conditions (Section III.3 of the permit).

Section II.55, 40 CFR Part 63 Subpart UUU Requirements:

- The following requirements were removed because they have been completed. Note that the source did not request that the requirements listed in *italics* be removed from the permit but since they had been completed the Division removed the requirements. *55.1 through 55.3*, *55.11 through 55.14*, *55.25 through 55.28*, 55.42, 55.43, 55.44,55.51, 55.52, 55.53, 55.54, 55.55, 55.65, 55.66, 55.67, *55.86 through 55.88*, *55.107, 55.108*, 55.109
- The following requirements were removed because they do not apply (these either apply to emission limitations that were not chosen or never applied). Note that the source did not request that the requirements listed in *italics* be removed from the permit but since they did not apply the Division removed the requirements. 55.5, 55.9, 55.10, 55.17, 55.18, 55.24, 55.25, 55.38, 55.39, 55.40. 55.41, 55.59, 55.63, 55.63, 55.64, *55.70 through 55.78*, *55.94*, 55.102 through

55.106,

- In addition, some requirements were revised to specifically identify the emission limitation and/or monitoring method.

Section II.58

- The source requested that the frequency of visible emission observations for the truck rack and rail rack flare be reduced from daily to monthly, with provisions for reducing monthly observations to quarterly, if no visible emissions are detected. The Division considers that the daily visible emission observations are still warranted; therefore, the changes requested by the source have not been made.

"New" Section II.65

- The source requested that the requirements in 40 CFR Part 60 Subpart VV be included in the permit. Although these requirements are not directly applicable to equipment at the facility, they are required via other applicable requirements (e.g., 40 CFR Part 63 Subpart CC and 40 CFR Part 60 Subpart GGG).

"New" Section II.66

- The source requested that the requirements in 40 CFR Part 61 Subpart FF be included in the permit.

"New" Section II.67 and Appendix I

- The source has indicated that the portions of the facility (the truck rack) are subject to the requirements in 40 CFR Part 63 Subpart GGGGG and that those applicable requirements be included in the permit. The source included a site diagram, which indicates those portions of the facility that are subject to Subpart GGGGG. The site diagram has been included in Appendix I of the permit.
- The source requested that the requirements from 63.7881(c) and 63.7884(b) be included in the permit. Both of these sections are essentially exemptions from the substantive requirements of Subpart GGGGG.
    - o Note that the requirements 63.7881(c)(3) were not included as this relates to including requirements into the Title V permit.

CAM Requirements

CAM applies to any emission unit that is subject to an emission limitation, uses a control device to achieve compliance with that emission limitation and has potential pre-control emissions greater than major source levels. The renewal application indicated that the FCCU was subject to CAM for particulate matter emissions (the FCCU is equipped with a third stage separator to reduce PM emissions). However, there are additional emission units with control devices and the renewal application does not indicate the reasons that these other emission units are not subject to the CAM requirements. Therefore, the Division conducted an analysis to determine whether any additional emission units are subject to CAM.

SRU #1 and SRU #2: In the current Title V permit, SRU #1 is equipped with a tail gas incinerator and SRU #2 is equipped with a tail gas recovery unit. Modifications have been made to the facility to equip both SRUs with a tail gas unit and a tail gas incinerator to control SO_2 emissions. These modifications were addressed in construction permit (04AD0111, issued May 24, 2004) and a modification to incorporate this construction permit into the Title V permit was submitted on January 12, 2007, which is being addressed in conjunction with this renewal application. Pre-control potential emissions of SO_2 from each SRU are above the major source level and the control device (tail gas recovery unit and tail gas incinerator) is necessary to meet the SO_2 emission limitations specified in the construction permit. However, the current Title V permit requires SO_2 continuous emission monitoring systems (CEMS) for both SRUs (the permit requires that an SO_2 CEMS be installed on SRU #2 by September 30, 2002). Therefore, although the requirements for Construction Permit 04AD0111 are being incorporated into this renewal permit, because the current permit requires SO_2 CEMS, the Division considers that CAM does not apply to the SRUs because the Title V permit specifies a continuous compliance determination method (SO_2 CEMS), these units are exempt from CAM in accordance with the provisions in 40 CFR Part 64 § 64.2(b)(1)(vi).

Rail Rack and Truck Rack Flares: Both the rail rack (R101) and the truck rack (R102) are equipped with flares to control VOC emissions and rely on the flare to meet annual VOC emission limitations. The preliminary analyses for the construction permits issued for both the rail and truck rack, indicate that a flare control efficiency of 99% or higher was used to set the annual VOC emission limitations. At that control efficiency, uncontrolled emissions from both the rail and truck rack are above the major source level. However, the current Title V permit indicates that both flares are subject to the requirements in 40 CFR Part 60 Subpart A, § 60.18 (included in Section II, Condition 50 of the permit), which specifies that flares be operated with a flame present at all times (60.18(b)(2)) and that the presence of a flare pilot flame shall be monitored using a thermocouple or any other equivalent device to detect the presence of a flame (60.18(f)(2)). Therefore, the Division considers that CAM does not apply to the rail and truck rack flares, because the Title V permit specifies a continuous compliance determination method (thermocouple or equivalent to detect the presence of a flare), these units are exempt from CAM in accordance with the provisions in 40 CFR Part 64 § 64.2(b)(1)(vi).

FCCU

The Division agrees that the FCCU is subject to CAM with respect to the PM emission limitation of 1 lb/1,000 lbs coke burn-off (Section II, Condition 25.15.1).

Note that while the current Title V permit requires a program of NO_X and SO_2 reductions (per the Consent Decree) via the use of NO_X and SO_2 reducing catalysts and requires that the permittee set SO_2 and NO_X emission limitations based on the results of an optimization process, the Division does not consider that CAM applies with respect to NO_X and SO_2 emissions for the following reasons. On the one hand, it is not clear that that the NO_X and SO_2 reducing catalysts would meet the definition of a control device as specified in the CAM rule. In general, the CAM definition of a control device generally considers control devices to be equipment that is used to destroy or remove air pollutants prior to discharge to the atmosphere, which seems to preclude the use of a catalyst. However, the permit requires that both NO_X and SO_2 CEMS be installed on the FCCU to monitor compliance with the SO_2 and NO_X emission limitations; therefore, since the current Title V permit specifies a continuous compliance determination method (NO_X and SO_2 CEMS), the FCCU is exempt from CAM in accordance with the provisions in 40 CFR Part 64 § 64.2(b)(1)(vi).

The source submitted a CAM plan with the renewal application. In their CAM plan, the source indicated that post-control PM emissions from the FCCU were above 100 tons per year, which means that the frequency of monitoring must be continuous. The source proposed opacity as the indicator and since the FCCU is equipped with a continuous opacity monitoring system (COMS), monitoring of opacity will be continuous. The source proposed an indicator range of 30% opacity, except for one 6-minute average opacity reading in any 1-hour period. The source's justification was that this is the compliance method specified in 40 CFR Part 63 Subpart UUU for metal HAP emissions for units subject to NSPS Subpart J particulate matter requirements and the approach was selected for consistency, since the unit is subject to both requirements.

As specified in 64.4(b)(4), the CAM rule indicates that presumptively acceptable monitoring includes "monitoring included for standards exempt from this part pursuant to 64.2(b)(1)(i) or (vi) to the extent such monitoring is applicable to the performance of the control device (and associated capture system) for the pollutant specific emission unit".

The FCCU PM and PM_{10} limits (1 lb/1,000 lbs coke burn-off) are Consent Decree limits and are the same as the NSPS J particulate matter limits for FCCUs. The FCCU is also subject to requirements in 40 CFR Part 63 Subpart UUU and those emission limitations are exempt from CAM under 64.2(b)(1)(i) (standards under Section 111 or 112 proposed after November 15, 1990). One of the emission limitations options in MACT Subpart UUU for metal HAP emissions is to meet the NSPS Subpart J PM requirements (1 lb/1,000 lbs/ton coke burn-off and 30% opacity except for one is for one 6-minute average opacity reading in any 1-hour period). Since the Consent Decree stipulated that the FCCU is subject to the NSPS Subpart J PM requirement, this is the compliance option Suncor must use to comply with the metal HAP limit in MACT Subpart UUU. In addition to recordkeeping requirements (daily average coke burn-off rate and hours of operation for each catalyst regenerator), continuous compliance with the MACT Subpart UUU metal HAP emission limit is monitored by using the COMS and maintaining each 6-minute average opacity at or below 30% (except for one 6- minute average during a 1-hour period). Therefore, the monitoring proposed by Suncor represents presumptively acceptable CAM.

Although Suncor's proposal for CAM is considered presumptively acceptable CAM, the

Division considers that since the FCCU is subject to a more stringent opacity limitation (the Reg1 20% opacity limit), the indicator range should be based on the lower opacity limit (except during those periods, when that limit does not apply). The Division considers that since this monitoring is similar to the monitoring for the metal HAP limit in 40 CFR Part 63 Subpart UUU this is acceptable monitoring for CAM.

Note that a CAM plan will not be included in the permit since the COMS is being used to monitor the indicator. Under the CAM requirements COMS that meet the requirements in 40 CFR Part 60 or 75 meet the general design criteria in § 64.3(a) and (b) (see 40 CFR Part 64 § 64.3(d)(2)).

The CAM requirements were included in the permit as follows:

- In Section I, a "new" Condition 6 was added to address CAM.
- Provisions for determining the site-specific opacity from performance tests was added in Section II, Condition 25.19.
- The CAM requirements were included in Section II, Condition 25.20.
- The CAM plan was included in Appendix J.

<u>Section III – Permit Shield</u>

- As part of the renewal application, the source requested that a number of requirements be added to the permit shield for non-applicable requirements (Section III.1). In general, those requirements were included as requested, except as follows:
    - The entry for the 0.0026% fuel sulfur limit in 90AD053 in Section III.1 was not removed but was moved to the shield for streamlined conditions (Section III.3).
    - The shield from Regulation No. 7, Sections I, III and V through XVII for pressurized tanks was not granted as insufficient justification was provided.
    - The shield from Regulation No. 7, Section VI.B.2.a was not granted for T74, T2, T3, T120, T2006 and T3201 as these are listed in Section II, Condition 5.1 as fixed roof tanks. In addition, the shield was not granted for T94 and T120 as these are identified in the January 26, 1996 Title V permit application as fixed roof tanks.
    - The shield from Regulation No. 7, Section VI.B.c was not granted for T67, T70, T75, T77, T78, T80, T776, T778, T1, T34, T55, T58, T775, T2010, T4501 and T777 since these tanks are in fact external floating roof tanks.
    - Although the Division granted the permit shield for 40 CFR Part 63 Subpart EEEE (Organic Liquids Distribution), it was granted based on an alternate justification.
    - The shield for the requirements from 40 CFR Part 60 Subpart GGG was not granted due to insufficient justification. Identifying which components <u>are</u>

subject to NSPS GGG is not a sufficient justification for inapplicability.

- o The shield for the requirements in 40 CFR Part 60 Subpart VV was not granted. The specific requirements for which the source wants to be shielded from must be specifically identified.
- o The shield for the requirements in 40 CFR Part 60 Subpart QQQ (except for 60.692-3) was not granted. Oil/water separators are subject to other provisions in Subpart QQQ such as control requirements for large units, delay of repair requirements and recordkeeping requirements.
- o The shield was requested for NSPS Subpart K, Kb and UU and MACT Subpart R for a number of tanks. The justification provided was that these tanks were constructed prior to the applicability date. The shield was granted for the NSPS requirements but not the MACT requirement, since the MACT does not have an applicability date (i.e., it applies to both new and existing sources at facilities that are major sources).
- o The source requested the shield from NSPS Kb for a number of tanks because the vapor pressure of the liquids were less than 3.5 KPa, the shield was granted for all tanks except T77 which is described in Section II, Condition 5.1 as a gasoline storage tank.
- o The Division included the shield for MACT CC for T7208 with a different justification than the one provided by the source.
- o The shield for a number of tanks from MACT Subpart R was requested with a justification that they were not located at a gasoline distribution facility. The shield was not provided for tanks T1, T34, T96, T97, T116, T2010 and T77 as these tanks all store gasoline and further justification is necessary to determine that these tanks are not located at a gasoline distribution facility.

1.9 September 26, 2008 Modification (minor modification) – SVE Engine

The source submitted an application to incorporate requirements for a soil vapor extraction (SVE) unit that will be used to recover hydrocarbon vapor from the soil at various sites. In the SVE unit, the VOC and HAPS extracted from the soil will be combusted in a trailer mounted internal combustion engine. The engine serves as both a vacuum pump to pull the VOC and HAP from the soil and a combustion device to control the extracted vapors. The engine is fueled by hydrocarbon vapor extracted from the soil and propane. Propane is used as a supplemental fuel to run the engine when the collected vapors are not adequate to power the engine.

The application indicates that the engine is a Remediation Services Int'l (RSI) engine, Model No. V3, rated at 50 hp and 0.60 MMBtu/hr. The engine is a 4-cycle rich burn engine that was purchased 10/17/2007 and manufactured in 1989. An APEN was submitted with the application indicating that emissions were as follows: NO_X – 5.81 tpy, CO – 9.78 tpy and all other criteria pollutant and HAP emissions were much less than 1 tpy. Emissions were estimated using AP-42 emission factors (Section 3.2 (dated

7/00), Table 3.2-3) and 8760 hrs/yr or operation.

The source also indicated that the engine will not remain in any one location for more than 12 consecutive months and as such is a non-road engine and is not subject to APEN reporting and/or permitting requirements. However, the source concluded that because the engine was located at a refinery and burns refinery fuel gas, it is subject to the requirements in NSPS Subpart Ja and therefore is a stationary engine and should be permitted as such.

Reg 3, Part A, Section I.B.31.b.(ii) indicates that an engine is not a non-road engine if it is regulated by a federal New Source Performance Standard under Section 111 of the Federal Act. However, the NSPS provisions apply to stationary sources, for example § 60.1(a) states that (emphasis added) “[e]xcept as provided in subparts B and C, the provisions of this part apply to the owner or operator of **any stationary source** which contains an affected facility…” and the definition of “stationary source” in Reg 3, Part A, Section I.B.43 includes the following statement (emphasis added) “[t]hose emissions resulting directly from an internal combustion engine for transportation purposes or from a non-road engine as defined in Section I.B.29. of this Part **shall not be considered a stationary source**.” Therefore, since a non-road engine is not a stationary source and the NSPS provisions only apply to stationary sources, the Division considers that the provisions in NSPS Ja do not apply to the SVE engine, because it is a non-road engine and not a stationary source.

In addition, since the SVE engine does not meet the requirements in Regulation No. 3, Part A, Sections I.B.31.c and d (state-only requirements for non-road engines), this engine is not subject to the APEN reporting and permitting requirements.

Although the engine is not subject to permitting requirements, the permit exemption does not apply if the engine is no longer considered a non-road engine (i.e., it remains in one location for more than 12 consecutive months). Therefore, language will be added to the permit in Section II.37 to address the fact that if the engine ceases to meet the definition of a non-road engine, permitting will be required for this engine. In addition, the engine was added to the tables in Section I, Condition 5.1 and Appendices B and C and noted as a non-road engine.

While the Division considers the engine to be a non-road engine and therefore not subject to permitting requirements provided that the engine is not in any one location for more than 12 consecutive months, the Division does consider that emissions from the soil vent are subject to permitting requirements provided emissions from the soil vent exceed the APEN de minimis level. Therefore, the Division has included emission limitations for VOC from the engine into the permit, since the engine is acting as a control device for the VOC emissions from the soil vent.

1.10 December 9, 2008 Modification (minor modification) – Tank T778 and Boilers B6 and B8

In this modification the source requested changes to tank T778 and Boilers B6 and B8.

In this modification, the permittee requested that tank T778 be allowed to store crude oil during periods when other crude oil storage tanks must be emptied for inspection. Tank T778 is currently storing naphtha and is grandfathered from construction permit requirements. In order to allow tank T778 to store crude as an alternative to naphtha, piping jumpers need to be installed to allow crude to be transferred tank T778. Requested emissions from the tank are based on the tank storing crude oil for a full 12 months rather than the short period of time it is expected to store crude.

Emissions from the tank were estimated at 3.54 tons/yr. The source also estimated emissions from component leaks (18 valves and 46 connectors (count includes 2 flanged connectors per valve) in light liquid service) to be 0.12 tons/yr. Emissions from component leaks were not included on the APEN submitted for tank T778, nor was a separate APEN submitted to address fugitive VOCs from new components. Since emissions from the new components are less than the APEN de minimis level of 1 tpy VOC, these emissions shall be reported on the plantwide fugitive VOC APEN (for components without permit limits).

The changes to tank T778 were addressed in the permit as follows:

- The table in Section I, Condition 5.1 was revised to indicate that crude oil may also be stored in Tank T778.
- Tank T778 was removed from Section II.1 and included in Section II.4 with the appropriate emission and throughput limits.

In addition to the changes to tank T778, the source requested that changes be made to the language for Boiler B6 and B8 to address requirements in the Consent Decree. Section II, Conditions 14.8 and 15.8 of the permit include language from paragraph 73(a) of the Consent Decree but do not include the full language. The source has requested that the full language in paragraph 73(a) of the Consent Decree be included in the permit.

The change related to B6 and B8 were addressed as follows:

- Section II, Conditions 14.8 and 15.8 were revised to include the full language in paragraph 73(a) of the second amendment (entered October 2006) to the Consent Decree.

1.11 February 10, 2009 Modification (minor modification) – SVE – Thermal Oxidizer

The February 10, 2009 modification is to permit an Oxidair Thermal Oxidation System (Oxidair unit) that is used to recover hydrocarbon vapors from soil at various sites at the Commerce City refinery. The Oxidair unit is a skid mounted horizontal combustor that is fired with propane. The vapor extracted from the soil with two blowers is mixed with supplemental fuel and combusted in a ceramic lined venture burner. Propane is used as the supplemental fuel. The Oxidair unit burner is designed to provide proper mixing of the vapor, air and supplemental fuel to assure complete combustion of the collected vapors. The Oxidair unit is rated at 0.31 MMBtu/hr, can process 150 scf/hr of soil vapor, was manufactured in 2000 and purchased by Suncor in 2007.

According to the application, the unit was purchased and delivered to Suncor in June 2007 and the unit began operating shortly thereafter. At that time, it was presumed that the unit did not require a permit since emissions were below the APEN de minimis level. However, upon further review it was determined that NSPS Subpart J applied to the unit because vapors extracted from soil were considered to be a refinery fuel gas. Therefore the unit was subject to APEN reporting and minor source construction permit requirements.

Emissions from the Oxidair Unit are as follows:

Pollutant	Emission Factor	Emission Factor Source	Emissions (tons/yr)*
NO_X	0.068 lb/MMBtu	AP-42, Section 13.5 (dated 9/91), Table 13.5-1, factor for VOC was determined by multiplying TOC factor by 0.45 (per Table 13.5-2, TOC is 55% methane)	0.14
CO	0.37 lb/MMBtu		0.74
VOC	0.063 lb/MMBtu		0.13

*Emissions are based on 8760 hrs/yr of operation and a total heat rate of (0.31 + 0.15) lb/MMBtu. The 0.15 lb/MMBtu is based on the assumption that the soil vapor has a heat content of 1,000 Btu/scf (a conservative assumption). The Oxidair unit can process 150 scf/hr of soil vapor.

Suncor submitted comments on the draft permit and technical review document on August 5, 2011. In those comments, the source indicated that the thermal oxidizer (SV2) was not longer in use. The source submitted an APEN cancellation form on October 14, 2011 for this emission unit.

1.12 June 1, 2009 Modification (minor modification) – Tank T2010

The June 1, 2009 modification is to increase the throughput limit for gasoline storage tank T2010. This tank was originally addressed in Colorado Construction Permit 97AD0699 (issued December 22, 1997) and that permit was incorporated into the current Title V permit. Although the source is requesting an increase in throughput, which usually results in an increase in emissions, the source is actually requesting a decrease in permitted emissions. The source indicated that when tank T-2010 was originally permitted in 1997 emissions were estimated assuming no guidepole controls on the tank (slotted guidepole with ungasketed sliding cover). However, the tank was constructed with guidepole controls (slotted guidepole with gasketed sliding cover and guidepole wiper). The guidepole controls significantly reduce emissions. The change in permitted emissions associated with this modification is summarized below:

VOC Emissions (tons/yr)		
Requested	Current Permitted	Change in Emissions
4.98	16.39	-11.41

The changes to tank T2010 were addressed as follows:

- The emission and throughput limits for tank T2010 in Section II.3 were revised as requested.

Since this modification only addressed an increase in throughput and there were no physical changes to tank T2010, no other applicable requirements are triggered by this modification.

1.13 October 8, 2009 Modification (minor modification) – OMD Piping Jumper

The purpose of the October 8, 2009 modification is to address the Oil Movements Division (OMD) piping jumper project. This project is intended to install a new piping jumper that will allow for the movement of refinery blendstocks and finished products in a manner that will help to reduce future truck driver wait time, idling emissions from gasoline tank trucks and potential demurrage fees at the Plant 1 Truck Rack. The OMD piping jumper project will involve the installation of a piping jumper to route low severity reformate from Tank 1 into the line from Tank 75 that is routed to the refinery blender and will allow the source to use a more convenient and preferred piping line-up than the existing line-ups currently in use.

The piping jumper is the only physical change associated with this project. An additional 10 valves and 25 connectors in light liquid service are expected to be installed with this project. The emission increase associated with the new components is 0.42 tons/yr of VOC emissions.

The OMD piping jumper project will not result in an increase in gasoline produced by the refinery and no modifications are being made to the online gasoline blending system, product tankage or the Plant 1 truck rack. In addition, the piping jumper does not connect Plant 1 to Plant 2 (East Plant). However, since the purpose of the OMD project is to decrease truck wait time, more gasoline can be loaded. The source has not requested an increase in the permitted throughput or emissions for the truck rack with this modification but did address an incremental increase in "actual" emissions from the truck rack. The source indicated that it was expected that with the addition of the OMD piping jumper an additional 10,411 bbls/day can be loaded through the truck rack. With new components and the increased utilization of the truck rack, increased emissions from this project are estimated as follows:

Source	Emissions (tons/yr)		
	NO_X	CO	VOC
Fugitive Emissions from New Components			0.42
Truck Rack	0.98	5.31	7.56
Total	0.98	5.31	7.98
PSD/NANSR Significance Level (T5 Minor Mod Level)	40	100	40

The source submitted an APEN for the truck rack but they are not requesting any increase in permitted emissions or throughput therefore no changes to the permit for the truck rack are required.

Although new components will be installed as part of this modification no APEN was submitted for emissions from those components, nor does it appear that they are addressed on the APEN for the truck rack. Since emissions from the new components are less than the APEN de minimis level of 1 tpy VOC, these emissions shall be reported on the plantwide fugitive VOC APEN (for components without permit limits).

1.14 October 15, 2009 (minor modification) – Catalytic Reforming Unit

The purpose of the October 15, 2009 modification is to make some revisions to the No. 1 Catalytic Reforming Unit. These changes are intended to reduce the overall energy consumption and heater firing rate intensities (emissions or energy consumption per unit of throughput), increase unit reliability and availability and reduce the frequency of reformer catalyst regenerations. A full list of proposed projects is noted in the October 15, 2009 application, although the source indicated that the exact scope of the proposed changes are not known as many of them will have to be made individually and evaluated before the next modification can be made. The application indicates that the first modification (addition of ceramic coatings to the reformer heater tubes) is expected to occur in October 2009 and that construction will continue through reformer regenerations (which occur approximately once per 6 – 12 month period) and during the next anticipated full plant turnaround (planned for 2011).

In their application, the source summarized expected emissions from the project (new equipment, modified equipment and non-modified equipment with increased emissions due to either de-bottlenecking or increased utilization). The only new equipment associated with this modification are the installation of new components which will result in fugitive VOC emissions from leaks. The source estimated the component count as follows: 25 valves (light liquid), 25 valves (gaseous), 100 flanges/connectors, 2 sampling systems and 2 pumps (light liquid).

In the application, the source indicated that the heaters (H-28, H-29 and H-30) will be directly modified to include the addition of ceramic coatings and potential changes to the pre-heater and burners. However, the design rate (MMBtu/hr) of the heaters will not be changed with this modification and the source is not requesting an increase in current permitted emissions for these units (current permit limits are below the PSD significance levels); therefore, the source estimated the increase in emissions from the heaters as the change in actual emissions (potential (current permitted) minus last 2 years actual emissions (9/07 – 10/09)).

Also in the application, the source indicated that increases from non-modified equipment would only be from an increased demand for steam (500 lbs/hr of 175 lb steam) and the increased throughput to storage tanks (the purpose of the project is to increase the availability of the reformer so there should be an increase in reformate). Although this increase in throughput may be reflected in several tanks (Plant 1 tanks T1, T70 or T75), the source conservatively assumed that the increase in throughput was processed through tank T1 which would give the highest emission estimate. The increase in emissions is estimated as the change in actual emissions (potential minus average of last 2 years actual emissions (9/07 – 10/09)). The source indicated that the reformer is not a bottleneck for any upstream or downstream processing units.

The source estimated total project emissions for changes to the No. 1 catalytic reformer were estimated as follow:

Source	Emissions Increase (tons/yr)				
	NO_X	CO	VOC	PM/PM_{10}	SO_2
Fugitive VOCs from new components			4.5		
Heaters H-28, H29 and H-30[1]	9.5	15.8	1.0	1.4	9.9
Boiler 4[2]	0.97	0.29	0.02	0.03	0.12
Tank T1[1]			11.95		
Total	10.47	16.09	17.47	1.43	10.02
PSD/NANSR Significance Level (T5 Minor Mod Level)	40	100	40	25/15	40

[1]Not a modified emission unit and no increase in permit limits were requested. Increased emissions are based on the increase in actual emissions (potential minus average of last 2 years actual emissions (Sept 2007 through August 2009). Note that potential emissions are equal to permitted emissions and potential emissions are as follows: NO_X – 20.4 tpy, CO – 34.2 tpy, VOC – 2.2 tpy, PM/PM_{10} – 3.1 tpy, SO_2 – 10.5 tpy.

[2]Not a modified emission unit and no increase in permit limits were requested. Increased emissions are from the incremental increase in emissions due the additional steam demands.

The application indicates that no APEN was submitted since there was no new equipment associated with this modification. However, the application clearly indicates that new components will be added. Since emissions from the new components exceed the APEN de minimis level, an APEN is required for these new components. The source submitted a revised APEN on November 15, 2011.

The following revisions were made to the permit to address the revisions to the No. 1 catalytic reforming unit:

- The new components and appropriate emission limitations were added to Section II.34 of the permit.

1.15 February 11, 2010 Modification (administrative amendment) – Tank T4501

The purpose of the February 11, 2010 modification is to change the description of the material stored in tank T4501. The tank is currently used to store slop oil and water mixtures from the sweet and sour crude unit desalters. However with the construction and operation of the new wastewater treatment system the water mixture will no longer be sent to T4501 but will be sent to the new oil/water separators and T4501 will only store slop oil.

The source has indicated that when the oil/water mixture is sent to the new oil/water separators, the tank will no longer operate as a static level tank but will operate as a variable level tank. The source indicated that they were not requesting an increase in the current permitted emission or throughput limitations but just a change in the text in Condition 3.15.

Suncor had previously submitted a modification on April 7, 2008 to route desalter water from Plant 2 to this tank and requested an increase in both the throughput and emission limitations. Since this particular modification specifically notes that no increase in throughput and emission limitations, the permit includes the throughput and emission limitations in the current permit (65,800,000 gallons/year and 2.75 tons/year of VOC). Note that the throughput limit was converted to barrels to be consistent with other tank throughput limits. The February 11, 2010 modification does not address emissions from tank T58 (as part of the April 7, 2008 modification application, the source requested throughput and emission limits for T58), therefore, the permit includes the emission and throughput limitations for T58 as indicated in the April 7, 2008 application.

During review of the comments on the draft permit and technical review document submitted on August 5, 2011, the Division considered that this tank is more properly addressed as part of the wastewater treatment system (the wastewater treatment system is in Section II, “new” Condition 23 of the draft permit – in the current permit the wastewater treatment section is addressed in Condition 26 - the API Separators). Therefore, the appropriate applicable requirements for Tank T4501 have been included in Section II, “new” Condition 23.

As requested in the February 11, 2010 application, the language indicating that the tank T4501 stores a two-phase material and that tank contents are not stored at ambient temperatures will be removed (this language was included in Section II, Condition 3.15 of the current permit).

1.16 March 3, 2010 Modification (minor modification) – Tank T52

The purpose of this modification is to re-permit tank T52. This tank was originally permitted to store naphtha under Colorado Construction Permit 90AD502. As part of the application for the Clean Fuels Project (submitted January 2004) the source proposed to change the service of the tank from sweet naphtha to sour water storage. In November 2005, the source requested that the permit be cancelled for T52 since it would no longer store hydrocarbons. At the time the permit was cancelled the source considered that T52 would no longer store hydrocarbons and would operate as a component of the refinery wastewater system and would no longer be subject to regulation under 40 CFR Part 60 Subpart Kb, 40 CFR Part 63 Subpart CC or Colorado Regulation No. 7.

However in the Clean Fuels Project application, the source indicated that an oil skimmer would be installed on T52, the purpose of which was to properly manage the layer of diesel that is used to minimize the volatilization of H_2S from the sour water. After further review and discussions with the Division, the source considers that because a thin layer of hydrocarbon remains on the surface of the storage tank and that layer is in contact with tank roof seals, it is in fact more correctly permitted as a hydrocarbon storage tank, even though the primary purpose of this tank is to store sour water.

The hydrocarbon layer is diesel, so the applicability of various requirements for the tank is based on diesel storage. In addition, the emission and throughput limits are based on the tank storing diesel, as opposed to sour water.

The re-permitting of tank T52 was addressed as follows:

- Tank T52 was included in the tables in Section I, Condition 5.1 and Appendices B and C.
- The appropriate permit conditions were included in Section II.4 of the permit.

  The conditions for tank T52 were previously included in Section II.3, however, since the tank is no longer subject to NSPS Kb (materials stored will have a true vapor pressure less than 3.5 kPa), it is more appropriately included in Section II.4.
- The appropriate Reg 7 sections that apply to this tank are Sections III.A and VI.A.1.

  Previously this tank was subject to Reg 7, Sections VI.B.2.b and VI.B.2.c but is now no longer subject to these requirements since diesel fuel is the only organic fuel stored in the tank in accordance with the requirements in VI.B.1.a.(i).
- This tank is subject to 40 CFR Part 63 Subpart CC as a Group 2 tank.

  Previously this tank was a Group 1 tank but because the tank has a stored-liquid maximum vapor pressure less than 1.51 psia and an annual average true vapor pressure less than 1.20 psia it is no longer a Group 1 tank.

1.17 March 11, 2010 Modification (minor modification) – H_2 Optimization Project

The purpose of this modification is to optimize hydrogen (H_2) use throughout the refinery. The source is proposing to install new piping (and associated valves and connectors) and an automated advanced control system to optimize the operation of the H_2 plant to reduce the net natural gas purchases for the H_2 plant feed and makeup fuel gas.

The No. 1 reformer (Plant 1), No. 2 reformer (Plant 2 – East Plant) and the H_2 plant (Plant 1) all make hydrogen that is used by the refinery hydrotreaters. The modifications made for this H_2 optimization project will allow hydrogen generated by the Plant 2 reformer to be used at Plant 1. This will reduce the load on the Plant 1 H_2 plant. Steam needs for Plant 1 are met by the Plant 1 boilers (B-4, B-6 and B-8) and the H_2 Plant. Decreasing the load of the H_2 plant will result in an increase in the utilization of the Plant 1 boilers to fulfill the Plant 1 steam needs.

In addition, the source indicates that depending on a variety of factors, fuel gas in Plant 1 may exceed fuel gas demand. Reducing the amount of reformer hydrogen routed to the fuel gas may help rectify this situation but balancing the heating value in the fuel gas system is necessary to reduce energy waste at the refinery. In part, the increase in fuel gas at Plant 1 is a result of transferring reformer hydrogen from Plant 2 to Plant 1, therefore, in order to balance the heating value in the refinery fuel gas system, excess fuel gas will be sent from Plant 1 to Plant 2. This will reduce the make-up natural gas use at Plant 2 and reduce flaring (and the associated combustion emissions from flaring) at Plant 1.

Project emissions are based on emissions from new equipment, modified equipment and non-modified equipment with increased emissions due to either de-bottlenecking or increased utilization. The source estimated project emissions from new equipment (piping components, which are a source of fugitive VOC emissions) and increased emissions from any non-modified equipment. Note that no existing equipment was modified with this project and the changes are not expected to de- bottleneck any upstream or downstream process units.

The new piping (and associated components) for the project involve installing a new line that feeds reformer hydrogen to the No. 3 HDS and a new line to take a purge stream from the No. 3 HDS to the No. 4 HDS (the No. 3 HDS has more stringent product tolerances than the No. 4 HDS). In addition new piping will be installed to connect the Plant 1 and Plant 2 fuel gas systems. The source estimated that there will be a total of 28 valves and 36 connectors in light liquid service.

Also in the application, the source indicated that increases from non-modified equipment would be from an increased demand for steam from the Plant 1 boilers, since the H_2 plant (which is a source of steam for Plant 1) will be run at near minimum rates. The source estimated that the increased steam needs to be 30,000 lb/hr of 175 lb steam. The increased steam needs were divided equally between the three boilers because normal operations are for all three boilers operating together (plant load is not covered by a single boiler). The incremental increase in boiler emissions was estimated using the incremental heat input needed to generate the steam, the emission factors specified in the title V or construction permit and 8760 hrs/yr of operation. Note that based on the Division's review, the source's estimated emissions increase is conservative as information submitted for another project indicate that the design steam rates for the boilers used in the source's evaluation were low, which resulted in a higher incremental heat input rate and subsequent emissions increase from each boiler.

The source did not evaluate any increase in emissions from the No.3 or No. 4 HDS other than the emissions from new components. The project includes installing a control valve on the existing reformer H_2 line to the No. 3 HDS and installing a new purge line (H_2) from the No. 3 HDS to the No. 4 HDS. The No. 3 HDS is currently capable of receiving reformer H_2 and H_2 is currently purged from the No. 3 HDS, however it is purged to the fuel gas system rather than the No. 4 HDS. The purpose of this project is to use more H_2 from the reformers (more is available since the purchase of Plant 2) and less from the H_2 plant. The H_2 plant was installed as part of the Clean Fuels Project (application submitted January 2004) in order to supply the additional H_2 needs and at that time, Plant 2 reformer H_2 was unavailable (Plant 2 was owned and operated by a separate entity). While the additional control valve and the purge line are physical changes the Division does not consider that these changes will result in an increase in emissions from the No. 3 and No. 4 HDS as these changes do not significantly change operation of the units. The No. 3 HDS was previously capable of receiving reformer H_2 (the reformer H2 line is not new, just the control valve) and the ability to purge H_2 from the No. 3 HDS was previously available but with the changes the purged H_2 will be fed to the No. 4 HDS. With the purged H_2 supplied to the No. 4 HDS, rather than the fuel gas system, less H_2 from the H_2 plant is necessary.

The source estimated total project emissions for changes for the H_2 optimization project were estimated as follows:

Source	Emissions Increase (tons/yr)				
	NO_X	CO	VOC	PM/PM_{10}	SO_2
Fugitive VOCs from new components			0.16		
Boiler 4[1]	19.43	5.83	0.38	0.53	2.32
Boiler 6[1]	2.42	2.42	0.33	0.45	1.98
Boiler 8[1]	3.51	3.51	0.47	0.65	2.88
Total	25.36	11.76	1.34	1.63	7.18
PSD/NANSR Significance Level (T5 Minor Mod Level)	40	100	40	25/15	40

[1]Not a modified emission unit and no increase in permit limits were requested. Increased emissions are from the incremental increase in emissions due to increased steam demands (less steam will be supplied by the H_2 plant).

No APEN was submitted with this application and no draft permit was submitted. The only new equipment associated with this modification is new components. Since emissions from the new components are less than the APEN de minimis level of 1 tpy VOC, these emissions shall be reported on the plantwide fugitive VOC APEN (for components without permit limits).

1.18 August 17, 2010 Modification (minor modification) – Tank T7208

The purpose of this modification is to increase ethanol fuel blending at the truck rack. Currently only two bays can load blended gasoline products. To increase ethanol fuel blending the source proposed to increase the permitted throughput at tank T7208 (this tank serves the truck rack) and make piping changes at two gasoline loading bays to allow loading of blended gasoline products. The source is requesting to increase the throughput at tank T7208 from 1,000,000 barrels/year to 2,095,000 barrels/year. The tank is permitted to store ethanol or any other organic liquid with a true vapor pressure less than or equal to 0.619 psia at 60 ºF. At the requested throughput level, requested emissions are at 0.39 tons/yr (previously the tank was permitted for 0.22 tons/yr of VOC). In addition, the source estimated fugitive VOC emissions from additional components (53 valves in light liquid service and 58 connectors) at 0.31 tons/yr. The source indicated that this change will not result in any increase in emissions from any upstream or downstream equipment. The source has not requested an increase in throughput or emissions at the truck rack. Permitted emissions at the truck rack are 29 tpy VOC, 4 tpy NO_X and 21 tpy of CO, all of which are below the PSD significance level.

A revised APEN was submitted for the tank and fugitive emissions from new components were reflected on the APEN for the tank (emissions noted as 0.39 + .31). Since emissions from the new components are less than the APEN de minimis level of 1 tpy VOC, these emissions shall be reported on the plantwide fugitive VOC APEN (for components without permit limits). The Division corrected the APEN to indicate requested emissions for the tank (T7208) only (0.39 tpy).

The following revisions were made to the permit to address T7208:

- Revised the emission and throughput limits for Tank T7208 in Section II.6.

1.19 October 13, 2010 Modification (unspecified modification type) – NSPS J Alternative Monitoring Plans

The primary purpose of the October 13, 2010 submittal is to rescind six previously approved alternative monitoring plans (AMPs) for the refinery (4 are associated with the West Plant (Plant 1) and 2 are associated with the East Plant (Plant 2)). AMPs were developed and approved as an alternative for the continuous monitoring requirements (monitoring the concentration of H_2S in fuel gas streams prior to burning) for fuel gas combustion devices under NSPS Subpart J. The source is requesting that these AMPs be rescinded because recent revisions to NSPS Subpart J were made to specifically exempt sources that are inherently low in sulfur content from the fuel gas combustion device continuous monitoring requirements (H_2S concentration in fuel gas streams). In addition to rescinding these AMPs, the source has requested that the permit language be revised to remove language regarding the AMPs and to indicate that no monitoring is required for these sources.

The Division agrees that three of the fuel gas streams at the West Plant (Plant 1) are exempt from the H_2S monitoring requirements as they are intolerant of sulfur and specifically exempt from the monitoring requirements as specified in 60.105(a)(4)(iv)(C) and are not required to follow the AMPs for these units.

In addition, while the fourth stream (recovered rail rack loading vapors), may also be exempt from the monitoring requirements as specified in 60.105(a)(4)(iv)(D), for such an exemption a demonstration must be submitted in accordance with the procedures in 60.105(b). In accordance with the provisions in 60.105(b)(2) the effective date of the exemption is the date of submission of the information in 60.105(b)(1) and the application for the exemption was submitted with the October 11, 2010 request to rescind the AMPs. Since this source has filed the information for an exemption, the Division considers that the recovered rail rack loading vapors are not subject to the H_2S monitoring requirements as specified in 60.105(a)(4)(iv)(D) and are not required to follow the AMP for this fuel gas stream.

The Division considers that since these fuel gas streams are exempt from monitoring, the AMPs are no longer in effect.

With respect with the requested permit changes, the Division has addressed the source’s concerns as follows:

- Revised Section II, Condition 38.2.1 addressing the exemption from monitoring and removed the paragraph indicating that the source must comply with AMPs.
- The following changes were made to Section II, Condition 27.2:
  - Revised the language regarding the NSPS J requirement. The language that is noted in the current permit as originating from the December 17, 2001 COC is not directly from the COC. The COC specified that the rail rack flare had to comply with NSPS Subpart J. As noted in the current language for Condition 27.2, an AMP was approved by EPA for the NSPS Subpart J requirements.
  - The source of the NSPS J requirement is noted as the federal Consent

Decree rather than the December 17, 2001 COC. The December 17, 2001 COC requirement has been included in the permit shield for streamlined conditions (Section III.3 of the permit).

- Included language to indicate the unit is exempt from H_2S monitoring.

1.20 October 29, 2010 Modification (minor modification) – Main Plant Flare Emission Factors

The purpose of this modification is to change the emission factors for the main plant flare. Currently the Title V permit specifies that emission factors from AP-42, Section 5.1. This modification requests the permit specify that emissions factors from AP-42, Section 13.5 be used instead, as they are more appropriate. The Division agrees that the emission factors from Section 13.5 are more appropriate. Since the flare was installed and commenced operation prior to February 1, 1972 it was not subject to construction permit requirements and does not have any annual emission limits. This change only reflects the emission factors used to estimate emissions for purposes of APEN reporting and fees.

The changes to the main plant flare were made as follows:

- The emission factors in both the table and text in Section II, Condition 31.1 were revised to reflect the new emission factors.
- The equation in Section II, Condition 31.1 was revised, since the emission factors are based on the quantity of gas combusted (in MMBtu), not the quantity of crude processed.
- Replaced the language in the Table in Condition 31.2 under the columns "Monitoring –Method, Interval" with "see Condition 31.2, as it more appropriately identifies the monitoring method.
- Revised Section II, Condition 31.5 was revised to require that the source determine the annual quantity of gas sent to the flare, rather than the actual crude processing rate.

1.21 November 1, 2010 Modification and September 7, 2007 (minor modification) – Tank T38

The purpose of both the 11/1/10 and 9/7/07 modifications were to re-build Tank T38.

The September 2007 modification proposed to build a new tank T38 (tank T38 was an 80,000 bbl tank that was removed from service in June 2006 and later demolished). In this application, the source indicated that the new tank T-38 would be used primarily to store Ultra Low Sulfur Diesel (ULSD), however, when tank T-94 is out of service, the tank will store kerosene. This application also indicated that the new tank T-38 would be an 80,000 bbl capacity, fixed roof tank, with requested throughput at 9,000,000 bbl/yr of jet kerosene or heavier petroleum product.

The November 2010 application indicates that work to construct the new tank T38 had not commenced yet as of application submittal. In this application the source also indicates a need to replace the original September 2007 application due to changes in tank dimensions and a need to replace the functionality of tank T33. This November 2010 application addresses the need for additional ULSD storage and kerosene storage during periods when tanks are out of service for inspection and any necessary repairs. As part of this modification the source proposes to replace the demolished 80,000 barrel and the existing 55,436 barrel fixed roof tank T33 with a new fixed roof tank T3801, with a maximum 53,138 barrel capacity. The requested annual throughput for the new tank T3801 is 20,095,096 barrels of kerosene and heavier petroleum products. Tank T33 will continue to operate until T3801 is constructed, hydro-tested and initially filled with petroleum liquid. In their comments on the draft permit (submitted on August 5, 2011 the source indicated that tank T33 has been removed, therefore references to tank T33 were removed from the permit. A cancellation form was submitted for tank T33 on August 25, 2011. In addition to new Tank T3801, the source has indicated that there will be minor changes to the piping configuration that will result in emissions from leaking components.

As discussed in both the September 2007 and November 2010 application, tank T3801 is not subject to the requirements in NSPS Kb because the true vapor pressure of the liquids stored are below 3.5 kPa (0.51 psia).

In addition, the tank is not subject to the requirements in Colorado Regulation No. 7, Section VI.B.2.a because the true vapor pressure of the liquids stored is less than 0.65 psia (per Reg 7, Section VI.B.2.a.(i)). The tank is subject to the requirements in Reg 7, Sections III.A, VI.A.1 and VI.B.2.b.

This tank is also subject to the requirements in 40 CFR Part 63 Subpart CC but qualifies as a Group 2 tank since the true vapor pressure of liquids stored is less than 10.4 kPa (1.51 psia).

Emissions from the tank were estimated at 2.19 tons/yr. The source also estimated emissions from new components (76 valves in heavy liquid service, 184 flanges/connectors and 3 sampling systems) to be 0.69 tons/yr.

A revised APEN was submitted for the tank and fugitive emissions from new components were reflected on the APEN for the tank (emissions noted as 2.19 + .69). Since emissions from the new components are less than the APEN de minimis level of 1 tpy VOC, these emissions shall be reported on the plantwide fugitive VOC APEN (for components without permit limits). The Division corrected the APEN to indicate requested emission for the tank (T3801) only (2.19 tpy).

The following changes were made to the permit to address tank T3801:

- <u>Section I and Appendices</u> – added the tank to the tables in Condition 5.1 and Appendices B and C
- <u>Section II.4</u> – added tank T3801 with the associated emission and throughput limits. Note that in the application, the source proposed to add the tank to Section II.1, however, this section is for external floating roof tanks for which construction permits are not required, and this section is not appropriate for a new fixed roof tank.

1.22 April 5, 2011 and December 22, 2010 Modification (minor modifications) – D133 and Wash Water Drum

The purpose of the December 22, 2010 modification is to install a new wash water system and a new accumulator drum to achieve better oil/water separation in the No. 3 crude unit (asphalt unit). The goal of the project, referred to as the D-133 and wash water drum project is to reduce under deposit corrosion in the overhead condensing section of the plant 3 fractionator (W-82) by installing a new wash water system, as well as a larger overhead accumulator drum in order to achieve better oil/water separation. This will allow for more efficient operation of the fractionator by decreasing backpressure caused by salt deposition in the overhead condensers.

The new equipment (wash water system and accumulator drum), will not by themselves be a source of emissions, however, there will be an incremental increase in emissions from equipment upstream and downstream of the No. 3 crude unit. There will be no physical change or change in the method of operation of existing equipment (e.g. process units, tanks, etc) but as previously stated there will be an incremental increase in emissions from existing equipment. In addition, new components will be installed and these will be a source of fugitive VOC emissions from the project.

A consequence of implementing the wash water system is that the crude temperature to the desalters will decrease, which can impact the overall operation of the No. 3 crude unit. Therefore additional heat exchangers will be added to maintain current operating temperatures, which will result in a small increase in steam demand during cold weather months. In addition, as a result to this project, lost production due to rate reductions from under deposit corrosion will be mitigated. Production losses at the No. 3 crude unit are estimated to be a maximum of 800 barrels/day. These estimates were based on several occurrences during February 2009 through September 2010 in which the No. 3 crude unit throughput was reduced by operational difficulties caused by factors that will be mitigated by this project.

On April 5, 2011, the source submitted a second minor modification application related to D-133 and the wash water drum. The purpose of this second modification was to notify the Division of a second project to increase the size of a number of control valves in the No. 3 crude unit. The purpose of the modification to the control valves on the No. 3 crude unit is to improve unit stability and control. This project will not increase the rated capacity of the No. 3 crude unit. While this project was planned as a separate project, given the timing of the two projects (D-133 and wash water drum and increase in control valve size) and because both projects affect the No. 3 crude unit, Suncor submitted the April 5, 2011 modification to aggregate both projects. The incremental increase in production from the second project is estimated at 3,394 barrels per day from the No. 3 crude unit (increase is based on design capacity of the crude unit (38,540 bpd) minus the baseline period production rate (35,146 bpd)).

In order to estimate impacts of the project on refinery operations, the source ran the Linear Programming (LP) model to calculate daily process feed rates and product amounts using the actual and projected crude throughput rates at the No. 3 crude unit. In addition to the new components (fugitive VOC emissions), incremental emissions from increased steam demands and restored production from the No. 3 crude unit are expected from the following equipment: heaters, boilers, No. 1 SRU, FCCU, storage tanks, petroleum loading, poly cat loading, wastewater treatment and cooling towers.

The source estimated total project emissions from the D-133/wash water drum and control valve projects as follows:

Source	Emissions Increase (tons/yr)					
	NO_X	CO	VOC	PM	PM_{10}/ $PM_{2.5}$	SO_2
Fugitive VOCs from new components			1.0			
No. 3 Crude Unit (H-6 & H-11)[1]	1.221	1.26	0.082	0.113	0.113	0.41
Naphtha Splitter/Stabilizer (H-20)[1]	0.137	0.115	0.008	0.010	0.010	0.037
No. 2 HDS (H-10 & H-19)[1]	0.146	0.117	0.008	0.010	0.010	0.038
No. 3 HDS (H-31 & H-32)[1]	0.73	0.372	0.033	0.083	0.083	0.17
No. 4 HDS (H-1716 & H-1717)[1]	0.66	0.89	0.117	0.164	0.164	0.60
FCCU (H-22)[1]	0.029	0.025	0.002	0.002	0.002	0.008
FCCU[1]	5.52	1.02	2.71	1.23	1.23	3.06
SRU/TGU (H-25)[1]	0.054	0.073	0.010	0.013	0.013	
SRU/TGU[1]						4.9
H_2 Plant (H-2101)[1]	9.75	0.16	1.406	1.96	1.96	19.13
Boilers (B4, B6, B8)[1]	8.76	2.45	0.436	0.60	0.60	2.16
Tanks[1, 2]			0.874			
Truck Rack[1]	0.22	1.25	1.10			0.03
Wastewater Treatment Plant (Plants 1 and 3)[1]			0.43			
Poly Cat Loading/Unloading[1]				0.079	0.079	
Cooling Towers[1, 3]			0.50	0.11	0.11	
Total	27.227	7.732	8.716	4.374	4.374	30.543
PSD/NANSR Significance Level (T5 Minor Mod Level)	40	100	40	25	15/10	40

[1]Not a modified emission unit and no increase in permit limits were requested. Increased emissions are from the incremental increase in emissions due to increased production of No. 3 crude unit (3,394 bpd) and increased steam demand.
[2]Relevant tanks are: T33, T66, T72, T75, T80, T2010, T2006, T3201 and T144
[3]Cooling Towers Y-1, Y-2, Y-3 and Y-4

The following revisions were made to the permit to address the D-133 and wash water drum project:

- The emission limitation was increased for the asphalt processing unit fugitives (F102) in Section II.34 of the permit.

1.23 May 13, 2011 Modification (minor modification) – Groundwater Remediation Storage Tanks – Cancellation Request Received June 20, 2012

The source submitted an application on May 13, 2011 to install several small storage tanks to contain organic material that is collected during remediation activities at Plant 1. According to the application, the tanks would only store organic material collected during remediation activities and will not store any raw material, intermediate or finished product produced by the refinery. The source has proposed the installation of eight (8) storage tanks, four (4) 1,000 gallon tanks and four (4) 525 gallon tanks. The application indicated that the larger tanks will be equipped with a closed vent system and two carbon canisters in series to control VOC emissions. The control efficiency of each canister is 95% (for an overall control efficiency of 99.75%). Requested emissions for this project are as follows:

Emission Unit	Requested Emissions (tons/yr)
Tanks	1.16
Fugitive VOCs from new components	0.05
Total	1.21
PSD/NANSR Significance Level (T5 Minor Mod Level)	40

In late November 2011, it became apparent that groundwater remediation efforts at the refinery and surrounding areas would be extensive and would involve significantly more equipment than what was addressed in the May 13, 2011 minor modification application. The Division provided enforcement discretion with respect to permitting the remediation equipment in order to allow for immediate remediation efforts. An application for construction permits for the remediation equipment and activities was submitted on May 21, 2012. This construction permit application addresses groundwater storage tanks associated with the remediation activities, as well as the other equipment necessary for the site remediation. Suncor submitted a request on June 20, 2012 to cancel the May 13, 2011 modification, since that application only represents a fraction of the tanks that have actually been installed for the remediation efforts and the tanks are addressed in the remediation construction permit application.

The Division has agreed to cancel the May 13, 2011 minor modification application since the application is not representative of the equipment installed (none of the 1,000 gal tanks were installed, and currently thirty (30) 525 gal tanks have been installed to address the remediation efforts at the refinery, with five (5) additional 525 tanks installed to address remediation efforts at the Metro Wastewater facility). The Division considers that the remediation activities resulting from contamination issues that surfaced in late 2011 are more appropriately addressed as a single project with the construction permit application that was recently submitted. Therefore, the requested provisions from the May 13, 2011 modification are no longer included in the renewal permit.

1.24 August 5, 2011 Comments on Draft Permit

Suncor submitted comments on the draft permit and technical review document on August 5, 2011. Comments were submitted as a red-lined version of the draft permit. A summary of the significant changes made with respect to this document are as follows:

- new wastewater treatment system

  Suncor made significant changes to the Plant 1 wastewater treatment system, including the replacement of the existing below-ground API separators with above-ground API separators and the Division requested that Suncor address these changes in their review of the draft permit. In their comments on the draft permit Suncor identified specific equipment in the wastewater treatment system that is subject to control under the provisions in 40 CFR Part 61 Subpart FF, National Emission Standard for Benzene Waste Operations (BWON). As part of their comments on the draft permit, Suncor addressed the addition of the relevant equipment into the permit and the appropriate applicable requirements in their red-lined draft permit primarily in Sections II.8, 9, 28, 71 and Appendix G. Following submittal of Suncor's red-lined draft permit, the Division met with Suncor to further discuss the wastewater treatment system and the appropriate applicable requirements for this equipment. As a result of the meeting, the wastewater treatment system is addressed in "new" Section II.23 of the draft permit with the appropriate applicable requirements (in the current permit Section II.23 addresses SRU #1 and in the current permit wastewater treatment operations are addressed in Section II.26 (API Separator)). The following issues should be noted with respect to the incorporation of these comments into the draft permit.

- NSPS Subpart Kb: The draft permit addressed tanks in Section II.8 and 9 in the red-lined permit and indicated that NSPS Subpart Kb applies to T60, T4514, T4515, T4516, T4517 and T4518. It's not clear why T4504 was not included in the list of tanks subject to NSPS Kb since it meets the size applicability for NSPS Kb. Therefore, the Division included T4504 as a tank subject NSPS Subpart Kb.

- Regulation No. 7: Suncor's red-lined draft permit did not address the applicability of Reg 7 requirements with respect to the tanks. The Division considers that tanks T60, T4501, T4502, T4503, T4504, T4507, T4508, T4516, T4517 and T4518 are subject to the requirements in Reg 7, Section III.A. Note that although the sumps are considered tanks under BWON, the Division doesn't consider them to be tanks under Reg 7; therefore they are not subject to general tank requirements in Reg 7 Section III.A. In addition, since the separators (T4514 and T4515) are subject to requirements in Reg 7, Section VIII.A, the Division considers that the separators are not subject to the general tank requirements in Section III.A.

  All of the tanks could potentially be subject to the requirements for petroleum liquid storage tanks in Reg 7, Section VI. Since T4514 and T4515 are oil-water separators and are subject to requirements in Reg 7, Section VIII.A, the Division considers that they are not subject to the tank requirements in Reg 7, Section VI. As discussed above for Reg 7, Section III.A, the Division does not consider the sumps tanks and therefore are not subject to the requirements in Reg 7, Section VI. The Division considers that all tanks are subject to the requirements in Reg 7, Section VI.A.1. Tanks T4502, T4503, T4507 and T4508 are less than 40,000 gallons, so they are only subject to the requirements in Reg 7, Section VI.B.3. Tanks T60 and T4501 are subject to the requirements in Reg 7, Section VI.B.2.b and c and tanks T4504, T4516, T4517 and T4518 are subject to the requirements in Reg 7, Section VI.B.2.a and b.

- o The Division revised the monitoring requirements for Reg 7, Section VIII.A (requirements for oil-water separators) to be consistent with the monitoring requirements in 40 CFR Part 61 Subpart FF (for T4514 and T4515) and 40 CFR Part 60 Subpart QQQ (for the asphalt sewer system CPI separator).
- o Suncor in practice defines “breakthrough” on the carbon canisters as 5 ppm benzene, rather than 50 ppm VOC as indicated in the Consent Decree. The 5 ppm benzene as breakthrough is consistent with the Valero Consent Decree (which covers the Suncor Plant 2 permit), therefore, the 50 ppm breakthrough definition (paragraph 90 of the Consent Decree) has been streamlined (included in Section III.3 – permit shield for streamlined conditions) in favor of the 5 ppm benzene breakthrough definition.
- o In the draft permit that was routed to Suncor for a pre-public comment review period, the Division had removed the requirements regarding 40 CFR Part 61 Subpart FF (BWON) from Appendix G as the requirements were no longer relevant because the total annual benzene was greater than 10 Mg/yr. Based on Suncor’s August 5, 2011 comments the Consent Decree BWON enhancement requirements were included in Appendix G.

- Suncor requested that the construction permits (09AD1351, 09AD1352 and 10AD1768) for the GBR equipment be incorporated into the permit. The Division included the GBR equipment into Section II, “new” Conditions 28 (09AD1351 – in the current permit this condition addresses the truck loading rack), 31 (10AD1768 –in the current permit this condition addresses the main plant flare) and 34 (09AD1352).

  Suncor submitted an update to the GBR project on May 23, 2011. This update addressed some additional piping run-downs that were not addressed in the initial GBR project application. In the May 23, 2011 update, Suncor indicated that piping would be added to allow the routing of high severity reformate from Plant 2 (east plant) directly to Tank T70 at Plant 1. The May 23, 2011 update indicates that all high severity reformate that is produced at the Commerce City Refinery is currently routed through Tank T70 at Plant 1. Currently Plant 2 high severity reformate is routed through Tanks T44 and 47 (located at Plant 2) before going to tank T70 (located at Plant 2). The piping change does not affect the amount of high severity reformate that is produced. However, there is a slight increase in VOC emissions from leaks associated with the new components. Estimated VOC emissions from leaks associated with the new components is 0.07 tons/yr. The preliminary analysis associated with the GBR construction permits indicated project VOC emissions at 12.79 tpy, so with the updated piping changes, VOC emissions from the GBR project are estimated at 12.86 tpy, which is still well below the major stationary source NSR significance level of 40 tons/yr.

- In their comments, Suncor indicated that they had three diesel fired emergency fire pump engines that do not qualify as non-road engines. These engines are subject to work practice requirements in the RICE MACT. Since these engines are subject to RICE MACT requirements under the catch-all language in Reg 3, Part C, Section II.E they can no longer be considered insignificant activities. Therefore, they have been included in “new” Section II.8 of the permit (note that Section II.8 of the current permit addresses H-6). “New” Section II.8 includes the RICE MACT requirements as well other applicable requirements for these engines, such as Reg 1 opacity and SO_2 requirements.

1.25 September 28, 2011 Modification (minor modification) – H-16 and H-18 Emission Calculations Methodology

The source submitted a modification application on September 28, 2011 to change the emission calculation methodology for heaters H-16 and H-18. The current permit indicates that emissions shall be based on hours of operation and the design heat input rate of the unit, since fuel flow to these units was not monitored. In their application, Suncor indicates that a fuel flow meter was installed to measure flow to these units in the summer of 2010 and has requested that the permit be revised to reflect this.

The following changes were made to the permit based on this request:

- Section II.59 was revised to indicate that this condition applies to H-16 and H-18 and to remove the provisions for relying on “maximum fired duty” for these units.

1.26 October 25, 2011 Modification (minor modification) – Bio-Diesel Load-In at Rail Rack

The source submitted a modification application on October 25, 2011 to allow the load-in of pure bio-diesel (B100) at the rail rack for storage in two tanks (T2004 and T2007) that previously stored sodium bisulfate. The bio-diesel (B100) would be imported from off-site. Based on the Division’s initial review of the application, the source submitted a revised application via e-mail on January 25, 2012 (hard copy submitted on January 30, 2012) to address the issues noted by the Division. Tanks T2004 and T2007 will be equipped to send B100 to pre-existing downstream storage tanks at both Plant 1 (T64, T65, T66 and T72) and Plant 2 (T8, T9, T30 and T43) where bio-diesel will be blended with petroleum products to produce bio-diesel blend products for sale.

Since tanks T2004 and T2007 will be used to store pure bio-diesel (B100), which is not made at the refinery and is not a petroleum product, these tanks are not subject to MACT CC. In addition, although the tanks are subject to general requirements for tanks in Colorado Regulation No. 7, Section III and V, they are not subject to any other specific requirements in Colorado Regulation No. 7. Since emissions from the tank are below the APEN de minimis level (1 ton/yr), can be considered insignificant activities. As part of this modification, the source requested that emission and throughput limits for the Plant 1 rail rack be revised to allow the load-in/-out of diesel fuel (including petroleum diesel, bio-diesel and petroleum/bio-diesel blends). The Plant 1 truck rack and the Plant 2 loading equipment currently allow the load-in/-out of diesel; therefore, no permit changes were required for this equipment.

Emissions associated with this project are as follows:

Source	Emissions Increase (tons/yr)		
	NO_X	CO	VOC
Fugitive VOC from new components			3.38
Tanks T2004 & T2007			0.04
Plant 1 tanks (T-64, T-65, T-66 & T-72)			0.29
Plant 2 tanks (T8, T9, T30 and T43)			0.30
Rail Rack – Loading[1]			1.50
Rail Rack – Fugitive (rail car venting)	0.86	4.67	0.61
Total	0.86	4.67	6.12
PSD/NANSR Significance Level (T5 Minor Mod Level)	40	100	40

[1]The emission increase from the rail rack loading is based on the loading of diesel, which the rail rack permit did not previously allow. Emissions from loading all materials were calculated differently (primarily due to a lower control device efficiency) which resulted in an emission increase for previously permitted materials (i.e. gasoline and JP-4). The increase in "permitted" emissions is as follows: NO_X – 1.17 tpy, CO – 6.12 tpy, and VOC – 3.61 tpy.

APENs were submitted for fugitive VOC emissions and the rail rack on January 25, 2012. The following changes were made to the permit to address this modification:

- The emission and throughput limits for the rail rack were revised in Section II.27, as requested.
- The new components and the appropriate emission limitations were included in the Section II.34.
- Tanks T2004 and T2007 were included in the insignificant activity list in Appendix A.

1.27 November 2011 and January and February 2012 Additional Information Submittals – Primarily Addressing the Wastewater Treatment System

While a number of information submittals were made in November 2011 and in January and February 2012 and these submittals addressed a number of issues associated with the processing of the renewal permit (e.g., comments on a second draft permit and additional information for a minor modification application), these submittals primarily addressed issues related to the wastewater treatment system. One of the significant changes to the Title V renewal permit were the changes made to appropriately reflect the requirements applicable to the wastewater treatment system. As indicated in Section 1.24, the source made physical changes to the Plant 1 wastewater treatment system (e.g. replacement of API separators) and in their August 15, 2011 comments on the draft permit, Suncor submitted a red-lined permit indicating the new equipment and the equipment equipped with controls to comply with the BWON requirements.

In an October 19, 2011 e-mail, the Division asked the source to submit APENS for the equipment that was equipped with BWON controls. The source submitted APENs on November 15, 2011 for the BWON controlled equipment; however, the APENs were incomplete and indicated that emissions from the wastewater treatment system were over 40 tons/yr of VOC. Since portions of the wastewater treatment system were new, the information provided in the November 15, 2011 submittal made it difficult to determine whether any of the wastewater treatment system might be subject to major new source review requirements. In a January 12, 2012 letter, the Division indicated the deficiencies in the APENs and identified issues that the source would need to address for the Division to determine how to appropriately address the wastewater treatment system. The source submitted revised APENs on January 30, 2012. The Division met with the source on February 1, 2012 regarding the January 30, 2012 APEN submittal and in this meeting the Division agreed that based on the method used to estimate emissions (EPA's Water9 Model) that submittal of three APENs (one each for the Plant 1, Plant 2 and Plant 3 wastewater treatment systems) would be more appropriate than an APEN for each controlled (or groups of controlled) emission unit(s). On February 27, 2012, the source submitted APENs for the Plant 1 and Plant 3 wastewater treatment systems. Since the Plant 2 equipment is addressed in another Title V permit and the Division is not aware of any modifications to the Plant 2 wastewater treatment system, an APEN for the Plant 2 equipment was not necessary at this time. The Division's review of the wastewater treatment system issues covered in the November 2011 and January and February 2012 submittals is as follows:

Overall Wastewater Treatment System

As previously indicated the APENs submitted on November 15, 2011 indicated that controlled emissions from the entire system were 65.55 tons/yr for the entire wastewater treatment system. This information raised a question as to whether any major new source review requirements were necessary since the submittal did not indicate the emissions for individual equipment and since portions of the system were relatively new, this information did not allow the Division to determine what, if any, major new source review permitting requirements might apply to the system. In addition, although the November 15, 2011 submittal indicated that emissions were based on EPA's Water9 model, no documentation to support the emission estimates were provided.

The January 30, 2012 submittal (hard copy submitted on January 31, 2012) included APENs for all the equipment that is equipped with controls in order to meet the BWON requirements. Emissions were estimated using EPA's Water9 Model and for the entire wastewater treatment system controlled emissions were 41.53 tons/yr. The source indicated that errors, such as failure to incorporate controls, were found in the Water9 model which was the basis for the emission estimates indicated on the November 15, 2011 APENs and such errors were corrected in the Water9 model that was used to estimate emissions on the January 30, 2012 APENs, hence the lower overall emissions from the wastewater treatment system.

In the February 27, 2012 APEN submittal, the source again made revisions to the EPA Water9 model, these revisions included the following: ensuring all controls for emission units were properly reflected, ensuring all flows and concentrations were updated and ensuring the accuracy of the model with respect to process flow and that all significant components were included. Based on the February 27, 2012 information, controlled emissions from the entire wastewater treatment system is less than 36 tons/year, which is below the PSD/NANSR significance level. Emissions from the Plants 1 and 3 wastewater treatment system will be permitted at the levels indicated on the February 27, 2012 APENs.

Plant 1 Wastewater Treatment System

The Division is aware that projects were conducted to modify the Plant 1 wastewater treatment system. One modification was to install a dissolved gas flotation (DGF) system for removal of oil and solids prior to bio-treatment. A second project was conducted to modify tank T60. Another was the upgrades discussed in Section 1.24 of this document, which was primarily to replace the existing below-ground API separators with above-ground APEN separators and other associated equipment changes (new and modified) necessary to comply with the BWON requirements. Although Suncor notified the Division regarding the DGF project in April 2006 and the Division indicated to Suncor that either a Title V permit modification or a construction permit was required, no such application for a permit was submitted. The Division is not aware that Suncor sought Division guidance in permitting the new API separators and other associated modifications to meet the BWON requirements, although the Division's Field Services Unit was aware of the changes. For the renewal permit emission limitations will be included for the Plant 1 wastewater treatment system to address these past instances in which the source failed to get a permit for new and/or modified equipment. Controlled emissions from both the January 30 and February 27, 2012 APEN submittals indicate emissions from the Plant 1 wastewater treatment system to be below the PSD/NANSR significance levels. An emission limit of 8.8 tons/year of VOC will be included in the permit for the Plant 1 wastewater treatment system (based on the February 27, 2012 APEN). It should be noted that emissions from tank T4501 will have a separate emission limitation, since this tank was previously permitted. In addition, emissions from the drains are not included in the limits for the Plant 1 wastewater treatment system. In general new and/or modified drains have been included in the permit limits for fugitive VOC emission sources.

Typically an emission limitation is usually associated with a throughput limitation for the given emission unit. However, given the fluctuations in flow rate and given the fact that the Water9 estimate is based on conservative assumptions a throughput limit will not be included in the permit. The permit will require that the Water9 model be run annually and that any revisions to the model be documented and made available to the Division upon request.

Plant 3 Wastewater Treatment System

The source submitted an application in 1991 to replace the Plant 3 (Asphalt Unit) wastewater treatment system. At that time estimated emissions from the new Plant 3 wastewater treatment system were 5.5 tons/yr of VOC. Although the Division issued a construction permit (91AD726R) that addressed the Plant 3 wastewater treatment system, this permit did not include an emission limitation for the new system but addressed the emission reduction credit associated with the replacing the existing asphalt unit wastewater treatment system and addressed certain control requirements for the new system. Based on the estimated emissions from this project, the permit should have included a VOC emission limitation for the new system. An emission limitation of 5 tons/yr of VOC has been included in the permit for the Plant 3 wastewater treatment system (based on the February 27, 2012 APEN). The emission limitation for the Plant 3 wastewater treatment system includes the drains. Emissions from the drains were estimated using the following emission factors:

Equipment Type	Emission Factor (lb/unit/hr)	Emission Factor Source
Drains, water seals	0.035	Suncor's internal guidance[1]
Junction boxes	0.035	Suncor's internal guidance[1]
Drains, capped	0.064	AP-42, Section 5.1 (dated 1/95), Table 5.1-3.

[1]The emission factor for junction boxes and drains with water seals, is equivalent to the AP-42 factor with an assumed control efficiency of ~45%. This factor is reasonable and is more conservative than the factor for water seal drains used in more recent construction permit applications. This factor is consistent with the emission factor used to estimate emissions in the 1991 application submitted for the new system.

As discussed above for the Plant 1 wastewater treatment system due to fluctuations in flow rate and the conservative assumptions used in the Water9 model, a throughput limit will not be included. The permit will require that emissions from the Plant 3 wastewater treatment system be monitored annually using Water9 for the CPI separator and the emission factors listed above for the drains.

1.28 February 7, 2012 Modification (minor modification) – Centrifuge Generator Engine

The source submitted an application on February 7, 2012 to obtain a permit for the diesel fired engine that is providing electrical power to the Plant 1 wastewater treatment system centrifuge. The engine was initially placed in its current location in March 2011 and will lose its non-road engine status in March 2012. Since the source does not expect to be able to provide permanent power to the centrifuge by that date, a permit is required for this engine. The February 7, 2012 application intended this unit to be permitted as a construction permit. However, because potential to emit from this engine are below the significance level and because the compliance determination method for the emission limitations in 40 CFR Part 60 Subpart IIII is the purchase of compliant equipment (i.e. a certified engine), the Division considers that this modification can be processed as a minor modification. As a result the source submitted a request to have this modification processed as a minor modification on March 21, 2012 and accepted the Division's draft permit on March 28, 2012, after which the Division deemed the application complete in a letter dated March 29, 2012.

The engine is an Isuzu, Model No.BH-6WG1X, Serial No. 3815310 and is rated at 532 hp/402.7 kW (max) and 464 hp/364 kW (site). In the original application the source indicated that site rated hp was 464 hp. Because the maximum engine horsepower is above 500 hp and the source did not provide information in the application as to how the engine's site rating was determined, the Division chose to independently verify that the engine is site rated at less than 500 hp (engines with a site rating > 500 hp are subject to emission limitations under 40 CFR Part 53 Subpart ZZZZ. Therefore, the Division determined that the based on a 3% reduction in power for every 1,000 ft above 3,000 ft, the site-rated hp is 498 hp. Since the Division independently verified that site rating is less than 500 hp and emissions are based on maximum ratings, the permit reflects the site-rating indicated in the original application. The generator is a WhisperWatt, Model No. DCA400SSI. The displacement of this engine is 2.61 liters/cylinder and it was manufactured in 2008.

Emissions associated with this modification are as follows:

	Emissions (tons/yr)[1]				
	$PM/PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
Requested Emissions (2,288 hrs/yr)	0.20	5.6×10^{-3}	4.06	3.55	1.32
Potential to Emit (8,760 hrs/yr)	0.78	0.02	15.55	13.61	5.05
PSD/NANSR Significance Level (T5 Minor Mod Level)	25/15/10	40	40	100	40

The engine is subject to requirements in 40 CFR Part 60 Subpart IIII, as well as opacity and SO_2 emission limitations in Colorado Regulation No. 1. Since the fuel restriction requirements in 40 CFR Part 60 Subpart IIII are more stringent than the SO_2 requirement in Colorado Regulation No. 1, the Reg 1 SO_2 limit has been streamlined and is included in the permit shield for streamlined conditions (Section III.3 of the permit). Since the site-rated horsepower of this engine is less than 500 hp, the requirements in 40 CFR Part 63 Subpart ZZZZ are met by complying with the requirements in 40 CFR Part 60 Subpart IIII.

PM, NO_X and CO emissions from the engine were estimated using the emission limitations in 40 CFR Part 60 Subpart IIII, maximum design rate and requested hours of operation. PM_{10} and $PM_{2.5}$ emissions are assumed to be equal to PM. VOC emissions are based on the emission factor in AP-42, Section 3.3 (dated 10/96), Table 3.3.1 (exhaust and crankcase). The Division estimated SO_2 emissions based on the fuel restriction in 40 CFR Part 60 Subpart IIII (15 ppm S), a diesel density of 7.05 lb/gal and the requested fuel consumption.

Pollutant	NSPS Subpart IIII Limit		Maximum Hourly Emission Rate[1] (lb/hr)	Converted Emission Factor[2] (lb/Mgal)
	g/kW-hr	g/hp-hr		
PM	0.20	0.15	0.18	7.69
NO_X-NMHC	4.0	2.98	3.55	151.7
CO	3.5	2.61	3.11	132.9
SO_2	Diesel fuel limited to 15 ppm S		4.91×10^{-3}	0.21
VOC				49.3

[1] The maximum hourly emission rate was determined as follows: For PM, NO_X and CO by multiplying the NSPS Subpart IIII limit (in g/kW-hr) x maximum design rate (402.7kW) and for SO_2 by multiplying the converted emission factor by the maximum hourly fuel consumption rate (23.4 gal/hr).

[2] The PM, NO_X and CO emission factors are based on the maximum hourly emission rate (lb/hr) divided by the

maximum hourly fuel consumption rate (23.4 gal/hr). The SO_2 emission factor is based on the NSPS Subpart IIII fuel limit of 15 ppm of S and a diesel density of 7.05 lb/gal. The VOC emission factor is from AP-42, Section 3.3 (dated 10/96), Table 3.3-1 (TOC factor for exhaust + crankcase = 0/36 lb/MMBtu) and was converted to lb/Mgal based on an assumed diesel heat content of 137,000 Btu/gal.

Since PM ,PM_{10}, $PM_{2.5}$ and SO_2 emissions at the requested fuel consumption level are below the APEN de minimis level, emission limitations for these pollutants were not included in the permit. The NO_X emission limitation (and emission factor) included in the permit are based on the NSPS Subpart IIII NO_X-NMHC limit.

The following changes were made to the permit to address this modification:

- The engine was included in “new: Section II.8 of the permit (note that Section II.8 of the current permit addresses H-6). The following requirements were included for this engine:
  - o Emission and throughput limitations
  - o Opacity requirements
  - o NSPS Subpart IIII and MACT Subpart ZZZ requirements

1.29 April 23, 2012 Modification (minor modification) – Centrifuge Operations Control Engine

Suncor submitted an application on April 23, 2012 to obtain a permit for two engines used to combust emissions from the centrifuge operations. The centrifuge is part of the Plant 1 wastewater treatment system. Wastewater from the refinery passes through two API separators (T4514 and T4515). Recovered oil from the separators is then routed to the slop oil tanks (T4516 and T4501). Slop oil is routed from the slop oil tanks to frac tanks via vaccum trucks and then through the centrifuge to further separate oils, water and solids. Vapors from the centrifuge operations are currently routed through two identical internal combustions engines for destruction.

The engines were initially installed in April 2011 as a temporary control technology and were considered non-road engines. Since these engines have been in place for more than twelve consecutive months, the engines can no longer be considered non-road engines and therefore the request to permit these engines.

Emissions from the centrifuge were included with the APENs submitted on February 27, 2012 to address emissions from the Plants 1 and 3 wastewater treatment system (see discussion in Section II.1.27). Emissions from the Plant 1 wastewater treatment system, which includes the centrifuge, were estimated using EPA’s Water9 Model. The control efficiency assumed for the centrifuge was 95% control and controlled emissions were estimated at 0.8657 tons/yr (based on the 95% control efficiency, uncontrolled emissions are 17.3 tons/yr). VOC emissions from the engines were based on the data from the performance test conducted on these engines in June 2011 and were estimated at 0.17 tons/yr in the modification application (note emissions in the application are based on 2,880 hrs/yr per engine at 8760 hrs/yr per engine, VOC emissions are 0.65 tons/yr). It should be noted that the emission rates used for VOC in the application were actually total hydrocarbons, which includes methane and ethane, therefore, VOC emissions are likely lower than these values.

The application indicates that the engines were converted to run on vapors with propane used as an assist gas. The engines do not power any equipment but collect vapors from the centrifuge operations. Typically only one engine runs at a time, although both engines can operate simultaneously if necessary to control emissions. According to the application the engine was initially manufactured in 1989 but extensive modifications to the engine were made in 2000. The engines are each rated at 50 hp and are 4-stroke rich burn engines.

The engines are not considered fuel burning equipment and therefore are not subject to the fuel burning requirements in Reg 1, Section III.A or Reg 6, Part B, Section II. The engines are subject to the opacity 20% requirements in Reg 1, Section II.A.1. Note that the Division considers that the specific conditions under which the 30% opacity requirements in Section II.A.4 apply are not applicable to these engines, since it is expected that the duration of startups and/or process modifications would be very short.

The engines are not subject to the requirements for fuel gas combustion devices in either NSPS Subparts J or Ja since vapors combusted to comply with wastewater are not considered fuel gas under Subpart J or Ja.

The engines are also potentially subject to requirements for engines under either 40 CFR Part 63 Subpart ZZZZ (MACT ZZZZ) or 40 CFR Part 60 Subpart JJJJ (NSPS JJJJ). The requirements in NSPS JJJJ apply to owners or operators whose engines commence construction after June 12, 2006 and were manufactured after certain specified dates. Under NSPS Subpart JJJJ commence construction is the date the engine was ordered. Although the engine order date was not specified in the application, the Division considers that the engine was likely ordered after June 12, 2006, since the centrifuge commenced operation in 2010. However, the engines were manufactured prior to July 1, 2008; therefore, the engines are not subject to the requirements in NSPS JJJJ.

The MACT ZZZZ requirements typically apply to all engines located at either major or area sources but the specific requirements depend on whether the engine is considered “new” or “existing”. For engines less than 500 hp located at major sources of HAPs, new engines are engines that commenced construction or reconstruction after June 12, 2006. However, the definition of commenced construction is different than NSPS JJJJ and is based on “on-site” fabrication or installation and it specifically excludes the removal of equipment from an existing location and reinstallation at a new location. Specifically it means that engines that are relocated are not considered to be “new” engines. Since the engines were modified in 2000, it would appear that these are existing engines, provided that they had been operating in some other location and they were simply relocated to the Suncor facility. However, the application is silent in regards to whether these engines operated at some other location in the past. Absent appropriate information from Suncor, the Division has assumed that these engines qualify as existing engines as they have operated elsewhere and have merely been relocated to the Suncor refinery. To that end, these engines are subject to work practice requirements under MACT ZZZZ.

The following changes were made to the permit to address this modification:

- The requirements applicable to the engine were included with the Plant 1 wastewater treatment equipment in “new” Section II.23. (Note that in the current permit Section II.23 addresses the No. 1 SRU and the Plant 1 wastewater treatment equipment (API separators) are addressed in Section II.26.) Requirements specific to the engine include the following:
  - o Opacity requirements
  - o MACT Subpart ZZZ requirements
  - o BWON control requirements

1.30 Potential Issues Regarding Project Aggregation

Suncor has submitted 29 applications (NOT including the renewal application and their August 5 and November 25, 2011 comments on the draft permit and technical review document) to modify their Title V permit, since the current permit was issued on December 18, 2006. Modifications have been received from October 2006 through April 2012, a period of approximately five and one-half years. Under the PSD and NANSR programs, modifications occurring over a relatively short period of time should be evaluated to determine whether the “minor modifications” are truly separate projects or whether any of the projects should be aggregated together to determine whether PSD and/or NANSR requirements apply. Therefore, an analysis was conducted to determine whether aggregation of any of the 29 projects should occur.

Of the various modifications, several do not result in any physical change or change in the method of operation to an existing emission unit and/or result in a new emission unit. Three of the submittals (including the August 5, 2011 comments on the draft permit) are related to incorporating new and/or revised construction permits into the Title V permit, another two are related to changing emissions factors and another eight, including the renewal, are related to changes in permit language or monitoring. Twenty modifications address some physical change or change in the method of operation that results in an increase in emissions from various equipment. It was these modifications, which occurred over the period of April 2007 through April 2012 that were reviewed for possible project aggregation.

In addition to the twenty modifications, four construction permit applications were submitted for the Suncor facility from July 2009 through August 2010. Although the Division addressed the appropriateness of aggregating the construction permit projects in the preliminary analyses prepared for the construction permits, the pending Title V modifications were not addressed at that time. In order to determine whether these minor modifications should be aggregated the Division reviewed the individual projects (including those covered by the construction permits) to determine whether or not they were truly independent projects. The Division reviewed the following permit applications and/or equipment groupings to determine if aggregation was warranted.

<u>Four construction permit applications</u>

Of the four construction permit applications, two address Plant 2 (East Plant) equipment and two address Plant 1 (West Plant) equipment. The four projects are the replacement of the air grid on the Plant 2 FCCU (application submitted 7/30/09), the replacement of three exiting boilers at Plant 2 with two new boilers (application submitted 11/24/09), the installation of a process unit for the gasoline benzene reduction (GBR) project at Plant 1 (application submitted 10/30/09) and the modification of the No. 4 HDS at Plant 1 (application submitted 8/13/10) to increase the severity of the operation in order to lower the sulfur concentration of the diesel stream to 15 ppm (referred to as the ultra low sulfur diesel (ULSD) project). Replacement of the air grid on the Plant 2 FCCU was necessary for the proper operation of the third stage separator (TSS) on the unit. Installation of the TSS was necessary in order to meet the particulate matter emission limitations specified in the Consent Decree (Valero Consent Decree No. SA-05-CA-0569 entered November 23, 2005). The replacement of the three existing boilers at Plant 2 with two new boilers is necessary to comply with the system wide NO_X reduction requirements specified in the Consent Decree (Valero Consent Decree No. SA-05-CA-0569 entered November 23, 2005) for refinery heaters and boilers greater than 40 MMBtu/hr. The GBR process unit is necessary in order to comply with the Mobile Source Air Toxics Rule. The purpose of the ULSD project is to meet diesel fuel standards that were promulgated on June 29, 2004 (60 FR 39168) for non-road engines. These projects address different parts of the refinery and serve different purposes. Together these projects do not increase the capacity of the refinery or debottleneck emission units within the refinery. Therefore, the Division considers that aggregation of these projects for purposes of PSD and/or NANSR review was not appropriate.

Tanks

Of the twenty modification applications, eleven of them address tanks. Two of the modifications address the installation of new tanks that are considered insignificant activities (these modifications also address loading racks). The remaining nine modifications address individual tanks and except for tanks T4501 and T38, no one tank was subject to more than one modification application. Two modification applications were submitted for tank T4501 but one of the requested modifications is an administrative change. The earlier application submitted for T4501 (4/7/08 minor mod) requested an increase in throughput and emissions, while the later modification (2/11/10 admin amendment) does not request a change in either throughput or emissions, hence the draft permit does not reflect any change in the emission or throughput limits for tank T4501. Two modification applications were submitted for tank T38, but the later application replaced the earlier application. Since these projects address different tanks the Division considers that aggregation of the tank modifications is not appropriate.

Soil Vapor Extraction (SVE) Units

Modification applications were submitted for an SVE engine on 9/26/08 and for an SVE thermal oxidation unit on 2/10/09. As discussed in this document, according to the application, the SVE engine will not remain in one location for more than 12 consecutive months, which makes this engine a non-road engine. A non-road engine is not a stationary source and as such is not subject to stationary source permitting requirements, such as PSD or Title V permitting. While the Division considers the engine to be a non-road engine and therefore not subject to permitting requirements provided that the engine is not in any one location for more than 12 consecutive months, the Division does consider that emissions from the soil vent are subject to permitting requirements provided emissions from the soil vent exceed the APEN de minimis level. Therefore, aggregation of the SVE units would only be appropriate to the extent that VOC emissions from the SVE engine would be aggregated with the SVE thermal oxidizer. Note that even if the engine failed to qualify as a non-road engine and the Division aggregated these projects together because they both address site remediation, emissions from both projects together are below the PSD significance levels as shown in the table below.

Project	Emissions (tons/yr)					
	PM	$PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
SVE – Engine	0.03	0.03		5.81	9.71	0.10
SVE – Oxidation Unit				0.14	0.74	0.13
Total	0.03	0.03		5.95	10.45	0.23
PSD/NANSR Significance Level	25	15/10	40	40	100	40

It should be noted that in their August 5, 2011 comments on the draft permit, the source indicated that the thermal oxidizer (SV2) was no longer in use. The source submitted an APEN cancellation form on October 14, 2011 for this emission unit.

Truck Rack

The following modifications address the truck rack: modification to load bio-diesel (received 4/18/07), modification to load more ethanol (received 8/17/10) and modification for OMD piping jumper (received 10/8/09). None of the modifications increase allowable emissions or throughput from the truck rack but one does increase the throughput and emission limitations for Tank T7208. In addition, these modifications will result in new equipment (new bio-additive storage tanks and additional piping and components). The time period between the bio-diesel project and the OMD piping jumper applications is 2 ½ years and the time between the OMD piping jumper and the ethanol increase application is nearly 1 year. Although these projects affect the same emission unit (the truck rack), they appear to be independent. However, even if the Division were to consider that these three projects were in fact one project, given that permitted emissions from the truck rack are below the significance levels, these projects, if aggregated would not trigger PSD and/or NANSR review. Permitted emissions from the truck rack and tank T7208, as well as estimated emissions from the new tanks and components are shown in the table below.

Project	Emissions (tons/yr)					
	PM	$PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
Truck Rack				4	21	29
Tank T7208						0.39
Bio-diesel project (new tanks/components)						0.72
OMD piping jumper (new components)						0.42
Total				4	21	30.53
PSD/NANSR Significance Level	25	15/10	40	40	100	40

Rail Rack

The 10/25/11 modification addressed modifications to load-in pure bio-diesel at the rail rack for storage in two proposed new tanks. The pure bio-diesel would be used to produce blends of bio-diesel and petroleum products for distribution and sale. As part of this modification the throughput and emission limits for the plant 1 rail rack were revised, since the rail rack was not permitted for loading of diesel fuel. The two new tanks qualify as insignificant activities. This modification is the only modification related to the rail rack but the modification is similar to other modifications, in particular the 4/18/07 modification to install a bio-diesel storage tank and modify the truck rack to allow loading of bio-diesel blended fuels. The rail rack bio-diesel modification was submitted 3 ½ years after the truck rack bio-diesel modification and therefore is outside of the range in which aggregation would generally be considered. Therefore, aggregation of the truck rack and rail rack bio-diesel modifications is not warranted.

Process Units

There is one modification that affects the catalytic reforming unit (10/15/09), one that relates to H_2 optimization (3/11/10) and two that relate to the asphalt unit (12/22/10 and 4/5/11). In addition, two of the recent construction permit applications relate to process units: they are the new GBR unit (application submitted 10/20/09) and the ULSD project (application submitted 8/13/10). Note that the other two recent construction permit applications are related to equipment at Plant 2 (East Plant) and have no connections to Plant 1 (West Plant). Therefore, they will not be considered further for purposes of aggregation. All of the modification applications relate to different process units and as a result are considered to be independent projects.

GBR Unit

The GBR unit is a new process unit that is necessary to comply with the Mobile Source Air Toxics (MSAT) Rule which requires refineries to produce gasoline with low benzene content. Essentially the GBR unit is another step in the process for reformate prior to blending reformate into product for sale. The GBR unit converts the benzene in reformate to cyclohexane which will result in a product with a lower benzene content. Therefore, based on the purpose of this project, the Division considers that this is most likely an independent project and should not be aggregated with other projects.

ULSD Project

The ULSD project is necessary to meet the lower diesel fuel standards for non-road engines. This project involves changes to increase the severity of the No 4 HDS in order to meet diesel fuel sulfur standards for non-road engines. The project primarily involves changes to the No. 4 HDS, although it also involves adding some “jumpover” lines to in the product rundown lines in order to improve the flexibility of diesel blending operations at Plant 1. Since this project is necessary to comply with future diesel fuel standards, the Division considers that this is an independent project and should not be aggregated with other projects.

D-133 and Wash Water Drum Project (Plant 3 Crude Unit)

The asphalt unit (plant 3 crude unit), is one of the first process units within the refinery process. Two modification applications were submitted in regards to the Plant 3 crude unit and both are designated as the D-133 and Wash Water drum project. The first application was submitted on December 22, 2011 and addressed the installation of a new wash water system and accumulator drum to achieve better oil/water separation in the No. 3 crude unit which would reduce under deposit corrosion in the overhead condensing section of the plant 3 fractionator. The reduced corrosion will restore some lost production due to operational problems. The second modification was submitted on April 5, 2011 and involved increasing the size of a number of control valves in the No. 3 crude unit. The purpose of the modification to the control vales is to improve unit stability and control. The control valve project will not increase the capacity of the No. 3 crude unit. Although these two projects were planned as independent projects, in their April 5, 2011 application, Suncor considered both projects together. As a result these projects have been aggregated.

The modifications to the No. 3 crude unit to restore lost production and increase the stability and control of the unit will result in increased emissions from a number of downstream process units due to increased production of the No. 3 crude unit (increased production is the difference between the design throughput rate of the unit and baseline actual throughput rate). Although some of the units affected by this modification due to increased utilization of support equipment (e.g. the boilers) are also affected units under other modifications the Division considers that these projects are independent projects intended to improve operations of the No. 3 crude unit and therefore should not be aggregated with other projects.

Catalytic Reforming Unit Project

The catalytic reforming project is a series of small physical changes/projects to the Plant 1 catalytic reforming unit (Plant 1 reformer). The projects are intended to reduce the unit's overall energy consumption and heater firing rate intensities (emissions or energy consumption per unit of throughput), increase unit reliability and availability, and reduce the frequency of reformer catalyst regenerations. The small projects were aggregated together in the October 15, 2009 application and the application considered the impacts of the projects on new components as well as emission increases due to the increased utilization of utilities (boilers) and increased storage tank throughput (due to increased availability of reformer). These projects address improvements to the catalytic reforming unit and do not debottleneck other process units within the refinery.

Reformate is a product of the reformer and is the feed stream that is treated by the GBR Unit. The Division does not consider that improvements to the Plant 1 reformer are necessary in order to proceed with the GBR project and the Division's assumption is supported since it appears that no improvements were made to the Plant 2 reformer (the Division is unaware of any changes to the Plant 2 reformer). However, since the applications for the two projects were submitted within days of each other (GBR unit application submitted on 10/20/09 and reformer application submitted on 10/15/09) aggregation of the projects may be warranted. While the Division is not necessarily convinced that either the Plant 1 reformer project or the GBR unit is dependent on the other (i.e. one could not effectively operate without the other), if these projects were aggregated, emissions would be below the significance level as indicated in the table below:

Project	Emissions (tons/yr)					
	PM	PM_{10}/$PM_{2.5}$	SO_2	NO_X	CO	VOC
Catalytic Reforming Unit	1.43	1.43	10.02	10.47	16.09	17.47
GBR Unit	3.83	3.83	5.29	22.06	21.23	12.86
Total	5.26	5.26	15.31	32.53	37.32	30.33
PSD/NANSR Significance Level	25	15/10	40	40	100	40

H_2 Optimization Project

The H_2 optimization project is intended to optimize H_2 use throughout the refinery. H_2 is generated by the Plant 1 (west plant) and Plant 2 (east plant) reformers and the H_2 plant (west plant) and used by the hydrodesulfurizers. The project was to install piping that allowed H_2 from the plant 2 reformer to be used at Plant 1. In addition, as part of this project, the source proposed changes to balance the heating value in the fuel gas systems. Due in part to transferring reformer hydrogen from Plant 2 to Plant 1, excess fuel gas may be generated at Plant 1. Therefore, changes will be made to route refinery fuel gas from Plant 1 to Plant 2, thus reducing the need to flare excess fuel gas at Plant 1 and reducing make-up natural gas usage at Plant 2. With these changes to utilize Plant 2 reformer H_2 at Plant 1, the H_2 plant will be used less. Increased emissions from this project included emissions from new components as well as increased utilization of the Plant 1 boilers in order to make up for reduced utilization of the H_2 plant (the H_2 plant also supplies steam to Plant 1).

The following projects could be reasonably considered for aggregation with the H_2 optimization project: the GBR unit, the catalytic reforming unit project and the ULSD project.

The primary purpose of the H_2 optimization project is to route H_2 from the Plant 2 reformer to Plant 1, which reduces the need to run the H_2 plant. One purpose of the catalytic reforming unit project (which affects the Plant 1 reformer) is to increase the unit's reliability and availability of the unit, which will likely result in more H_2 from the Plant 1 reformer. Since, the purpose of the H_2 optimization project is to route H_2 from the Plant 2 reformer to Plant 1, a potential increase in H_2 from the Plant 1 reformer due to the reformer project seems unrelated to the H_2 optimization project. The potential increase in H_2 production from the Plant 1 reformer due to the reformer project is likely minor in comparison with the additional H_2 from Plant 2 that t would be available via the H_2 optimization project. Therefore, the Division considers that the Plant 1 reformer project and the H_2 optimization project are not dependent on each other and aggregation of these two projects is not appropriate.

The Division previously stated that the GBR Unit is an independent project and aggregation is not warranted because it is a new process unit and is necessary to meet new MSAT requirements. However, since H_2 is a reactant in the GBR unit, the Division considers that further review may be necessary. According to the initial construction permit application for the GBR unit, it was expected that excess H_2 from Plant 1 would be sufficient for the GBR unit (per that application current excess H_2 is being routed to the fuel gas system) and the reboiler would be fired on Plant 1 refinery fuel gas (there was no indication that there were insufficient resources of Plant 1 refinery fuel gas). However, prior to permit issuance the source indicated that increased utilization of the

H_2 plant, although unlikely, might be necessary in the event that either the Plant 1 or Plant 2 reformer were unexpectedly shut down (the reformers supply both the feed stream and the H_2 to the GBR unit) or the GBR catalyst was fouled. To address this situation, the construction permit application considered emissions from the increased utilization of the hydrogen plant. At the request of the Division, Suncor submitted additional information on October 14, 2011 to address any potential relationship between the H_2 Optimization project and the GBR Unit project. To that end, Suncor has indicated that these projects are both technically and economically independent and would proceed regardless of the implementation of the other. Suncor indicated that neither project is dependent on the other in order to be constructed or operated, and when considered together, the two projects will not result in increased throughputs for any of the refinery units. Since the application of the GBR Unit (October 30, 2009) indicated that there was sufficient excess H_2 to meet the needs of the GBR unit and the purpose of the H_2 Optimization Project is to provide for more efficient use of the H_2 generated at the plant, the Division agrees that these are independent projects and aggregation of these projects is not warranted.

The purpose of the ULSD project is to increase the severity of operation of the No. 4 HDS so diesel fuel sulfur standards for non-road engines can be met. These changes include increasing the burner tip size of the No. 4 HDS heaters, adding heat exchange equipment, adding two electric pumps and “pump arounds” on the No. 4 HDS fractionator and modifying the internals of the HDS fractionators. Concurrently with the ULSD project, the source indicated that the HDS catalyst would be supplemented with another hydrotreating catalyst to increase the sulfur removal from the diesel stream. This change will allow the source to meet the lower ULSD sulfur specifications with the existing H_2 make-up compressor and without an increase in H_2 demand. As a result, the Division considers that the ULSD and the H_2 optimization projects are not dependent on each other and aggregation of these two projects is not necessary

Wastewater Treatment System

The source apparently conducted modifications to the Plant 1 wastewater treatment system, one related to the DGF system that commenced operation in 2007, one in 2008 (modification of tank T60) and one in 2010-2011 that addressed replacement of the existing below ground API separators with new above ground API separators and other associated equipment changes (API headworks, API and T60 lift station, API Centrifuge and slop oil system). The source did not submit permit applications for these modifications prior to commencing operation of the new and/or modified equipment. The Title V renewal permit will include emission limitations for the Plant 1 wastewater treatment system to address these past instances in which the source failed to obtain permits for new and/or modified equipment.

At the request of the Division, in their August 15, 2011 comments on the draft Title V permit, which included a red-lined permit, the source identified new equipment associated with the Plant 1 wastewater treatment system. The Division later requested that emission information be provided for the Plant 1 wastewater treatment system. Emission information was submitted November 15, 2011, with modified emission information submitted on January 30, 2012 and February 27, 2012. The emission limit for the Plant 1 wastewater treatment system included in the Title V renewal permit is based on requested emissions on the APEN submitted on February 27, 2012, which is 8.8 tons/yr of VOC and is below the significance level of 40 tons/yr.

In addition, as part of the Title V renewal permit, the Division included emission limits for the Plant 3 wastewater treatment system in the draft permit. A construction permit application was submitted in 1991 to upgrade the Plant 3 wastewater treatment system and while a construction permit was issued (91AD726R), the permit only addressed the emission reductions due to the replacement of the existing system, not emissions from the new system. Therefore, the draft renewal permit includes emission limitations for the Plant 3 wastewater treatment system based on requested emissions indicated on the February 27, 2012 APEN, which were 5 tons/yr of VOC.

The Plant 3 wastewater treatment system upgrades occurred long before any modifications commenced on the Plant 1 wastewater treatment system therefore aggregation of the Plant 1 and Plant 3 wastewater treatment system upgrades is not warranted. Note that the Plant 2 wastewater treatment system has not been modified, although, modifications to some of the equipment are expected in the future. A compliance order on consent (COC) was issued March 28, 2012 and requires that controls be installed on some equipment associated with the Plant 2 wastewater treatment system. These controls will reduce VOC emissions below the levels noted in the February 27, 2012 submittal.

It should be noted that the February 27, 2012 submittal address emissions from the wastewater treatment systems from all three plants and although the APENs were only submitted for Plants 1 and 3, the Division intends to include emission limitations for the Plant 2 wastewater treatment system in the Plant 2 Title V permit renewal permit. Based on the February 27, 2012 APENs, emissions from all three plants are below the significance level, as shown in the table below:

Source	VOC emissions (tons/yr)
Plant 1 Wastewater treatment system	8.8
Plant 2 Wastewater treatment system	24.7
Plant 3 Wastewater treatment system	5
Total	38.5
PSD/NANSR Significance Level	40

The upgrades to the Plant 1 wastewater treatment system occurred between 2007 and 2011. The source approached the Division in 2006 to determine if permitting was warranted for the 2007 project, which the source indicated was necessary to meet tighter standards on ammonia in wastewater. This project included the addition of the DGF system, which would serve as a secondary system of oil-water separation. The 2008 upgrade to tank T60 was part of the source’s BWON compliance strategy and the 2010 upgrades, specifically the new API separators and API lift station, were also identified as part of the source’s BWON compliance strategy. Although it appears that the 2007 upgrades may be a separate project, the source’s BWON compliance strategy was initially presented in 2006, therefore, the Division considers that aggregating the modifications to the Plant 1 wastewater treatment system are warranted. Upon issuance of the Title V permit, emissions from the Plant 1 wastewater treatment system will be below the significance level.

Modifications were submitted on February 7 and April 23, 2012 regarding the centrifuge which is part of the Plant 1 wastewater treatment system. The April 23, 2012 application addressed the engines used to control emissions from the centrifuge. Emissions from the centrifuge were addressed in the February 27, 2012 submittal and reported on the APENs submitted on that date, so the emissions indicated for the control device addressed in the April 23, 2012 submittal have already been assessed and reported (they are part of the 8.8 tons/yr reported on the February 27, 2012 APEN). The February 7, 2012 application addressed the internal combustion engine that is driving a generator that provides power to the centrifuge. Since the engine addressed in the February 7, 2012 application is part of the Plant 1 wastewater treatment system emissions from that generator engine should appropriately be considered with the other Plant 1 wastewater treatment system thus emissions from the Plant 1 wastewater treatment system upgrades are as shown in the table below:

	Emissions (tons/yr)[1]					
	PM	$PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
Centrifuge Generator Engine	0.20	0.20	5.6×10^{-3}	4.06	3.55	1.32
Plant 1 Wastewater treatment system						8.8
Total	0.20	0.20	5.6×10^{-3}	4.06	3.55	10.12
PSD/NANSR Significance Level (T5 Minor Mod Level)	25	15/10	40	40	100	40

Based on information available to the Division it appears that the modifications to the Plant 1 wastewater treatment system were intended to meet either wastewater or BWON requirements and not to add capacity to the system. In addition, it is not clear that modifications to the wastewater treatment system would be necessary for any of the other modifications addressed in this document, although increased utilization of the wastewater treatment system was considered with the D133 and Wash Water Drum modification (affected the Plant 3 crude unit). The Division considers that the modifications most likely to require an increased capacity to the wastewater treatment system would possibly be the GBR Unit (a new process unit) or the replacement of the Plant 2 boilers. With that said, as previously stated, the Division has no information to indicate that any of the modifications increased or were intended to increase the capacity and the following analysis is provided for informational purposes.

GBR Unit

In the GBR unit preliminary analysis increased utilization of the Plant 1 wastewater treatment system was not included in the assessment of project emissions. However, emissions from new wastewater drains were addressed and are included in the permit for fugitive emissions from the GBR unit. Although it does not appear that these projects are dependent (i.e., the modifications to the wastewater treatment system were necessary to operate the GBR unit), if these projects were aggregated, emissions from both projects would be below the significance level as indicate in the table below:

Project	Emissions (tons/yr)					
	PM	$PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
Plant 1 Wastewater treatment system*	0.20	0.20	5.6×10^{-3}	4.06	3.55	10.12
GBR Unit	3.83	3.83	5.29	22.06	21.23	12.86
Total	4.03	4.03	5.30	26.12	24.78	22.98
PSD/NANSR Significance Level	25	15/10	40	40	100	40

*Includes emissions from the centrifuge generator engine.

Plant 2 Boiler Replacement

At first glance it would seem that the Plant 1 wastewater treatment modifications would be unrelated to the Plant 2 boiler replacement project. Although Plant 2 does have dedicated wastewater treatment equipment, some of the equipment associated with the Plant 1 wastewater treatment system does handle wastewater from all three plants.

The intent of the Plant 2 boiler replacement project was to replace the existing boilers at Plant 2 with newer, cleaner units in order to meet requirements in the Consent Decree. Emissions from new wastewater drains were estimated and included in the permit for fugitive emissions from the Plant 2 boiler replacement project. Since the intent of the boiler project was to replace the existing boilers, it is not expected that there would be necessarily be an increase in the quantity of wastewater generated (hence no need for changes to the wastewater treatment system to allow for this project, which might indicate the projects are dependent and linked) but since the permitted annual heat input rate for the replacement boilers is somewhat higher than the permitted heat input rate for the existing boilers, the Division considers that consideration of these projects together may be warranted. Although the Division is not necessarily convinced that these projects are dependent up on another and thus would necessitate aggregation, an analysis of aggregated emissions from the two projects indicate that emissions are below the significance level as indicated in the table below:

Project	Emissions (tons/yr)					
	PM	$PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
Plant 1 Wastewater treatment system	0.20	0.20	5.6×10^{-3}	4.06	3.55	10.12
Plant 2 boiler replacement project	8.3	8.3	12.7	24.6	33.1	4.5
Total	8.5	8.5	12.7	28.66	36.65	14.62
PSD/NANSR Significance Level	25	15/10	40	40	100	40

Note that although permit applications for the GBR unit and the Plant 2 boiler replacement projects came in within the same year (2009), as previously discussed the Division considers that these projects are not dependent and do not warrant aggregation. Therefore, aggregating the Plant 1 wastewater treatment modifications with both the GBR unit and the Plant 2 boiler replacement projects is not warranted.

Given the independent nature of the Plant 1 wastewater treatment system modifications and the other projects addressed in this document, the Division considers that further aggregation of projects is not warranted.

1.31 Greenhouse Gas Analysis

Suncor has submitted 28 applications (not including the renewal application and the August 5 and November 25, 2011 comments on the draft permit) to modify their Title V permit, since the current permit was issued on December 18, 2006. As previously discussed several of these modifications do not result in any physical change or change in the method of operation to an existing emissions unit and/or result in a new emission unit. Under EPA's Tailoring Rule, which has been adopted into Colorado Regulation No. 3 by the Colorado Air Quality Control Commission, greenhouse gases (GHG) are subject to regulation for purposes of PSD review in a phased approach. In the first step, which applies to permits issued after January 2, 2011, GHG are only subject to regulation if PSD review applies for another regulated pollutant (e.g., the modification results in an increase in SO_2 emissions above the significance level). As discussed in this document, none of the modifications addressed in this permitting action result in an emission increase above the PSD significance levels, therefore, PSD review was not triggered and GHGs are not "subject to regulation".

The second step for GHG applies to permits issued after July 1, 2011 and applies to existing sources that have potential emissions of GHG at or above 100,000 tpy CO_2e and undertake a physical change or change in the method of operation that results in a GHG emission increase of 75,000 tpy CO_2e or more. The source must also be an existing stationary source for GHG emissions with potential to emit above 100 tpy or 250 tpy of GHG on a mass basis in order to trigger PSD review for GHG emissions. The Title V modifications that addressed physical changes or changes in the method of operation of existing equipment and/or new equipment were all requested as minor modifications under the Title V program. Although Colorado Regulation No. 3, Part C, Section X.I specifies that, "a source shall be allowed to make the changes proposed in its application for minor permit modification immediately after it files such application" because the revised permit addressing these modifications will be issued after July 1, 2011, these modification must be reviewed to determine if GHG are subject to regulation.

The facility has the potential to emit of GHG above 100,000 tpy CO_2e and 100 tpy GHG emissions on a "mass basis". Therefore, PSD review will be triggered for GHG emissions if emissions from any of the projects, exceed 75,000 tpy CO_2e. As previously discussed, emissions from each of the projects were below the PSD significance levels for non-GHG emissions and the Division did not consider that aggregation of projects was warranted. Rather than conducting an analysis for each project on its own, a conservative analysis that would cover each individual project was conducted.

GHG pollutants include CO_2 and N_2O, both of which are emitted from combustion sources. Therefore, projects with the highest emissions from combustion would result in the highest emissions of CO_2 and N_2O (these projects would also have high NO_X and CO emissions). The D133 and wash water drum project (No. 3 crude unit) was the individual project with the highest NO_X emissions; therefore, combustion emissions from this project were used in the analysis. The increase in NO_X emissions from this project was due to increased utilization of a number of process heaters and boilers at a total heat input rate of 89.86 MMBtu/hr. Emissions of CO_2 and N_2O were determined using AP-42 emission factors, the increased hourly heat input rate (89.86 MMBtu/hr) from the process heaters and boilers and 8760 hours per year of operation.

While VOC emissions exclude methane (which is a GHG pollutant), since methane is an organic compound, sources that emit VOC may also emit methane, so sources of VOC emissions can be a predictor for methane. The VOC emission sources from these projects are combustion sources, storage tanks, loading racks and fugitive emissions from component leaks. The storage tanks and loading racks at Suncor are not sources of methane emissions, therefore, projects with higher VOC emissions from combustion sources and/or fugitive emission sources are most likely to represent the project with the highest methane emissions. The D133 and wash water drum project (No. 3 crude unit) represents the highest VOC emissions from fuel burning (2.10 tpy VOC) and the additional components from the catalytic reforming project represent the project with the highest increase in VOC emissions from new components (4.5 tons/yr). Methane emission from fuel burning will be estimated as discussed above for CO_2 and N_2O (the increased hourly heat input rate of 89.86 MMBtu/hr and AP-42 emission factors). Emissions from equipment leaks are estimated using EPA's Protocol for Equipment Leak Estimates (EPA-453/R-95-017). In general the average emission factors included in Section 2.0 of this document are for total organic compounds (including methane); however, the refinery emission factors (listed in Table 2.2) exclude methane. The procedures in Section 2.0 specify that the equipment used in the Refinery Assessment Study (used to set emission factors) relied on equipment that contained less than 10 weight percent methane. Therefore total organic compound (TOC) emissions were estimated by dividing the estimated fugitive VOC emissions from the catalytic reforming unit project by 0.90 (TOC = 4.5/0.90 = 5). Methane emissions were then estimated by subtracting VOC emissions from the calculated TOC (methane = 5.0 – 4.5 = 0.5 tpy).

Estimated CO_2e emissions from the above analysis are shown in the table below:

Pollutant	Emission Factor (lb/MMBtu)[1]	Fuel Use (MMBtu/yr)[2]	Emissions (tons/yr)	Global Warming Potental[3]	CO_2e (tons/yr)
Methane – fuel burning	2.25×10^{-3}	787,174	0.88	21	18.6
Methane Equipment leaks	N/A[4]	N/A[4]	0.5	21	10.5
Nitrous Oxide (N_2O)	2.16×10^{-3}	787,174	0.85	310	263.5
CO_2	117.65	787,174	46,305.5	1	46,305.5

Pollutant	Emission Factor (lb/MMBtu)[1]	Fuel Use (MMBtu/yr)[2]	Emissions (tons/yr)	Global Warming Potental[3]	CO_2e (tons/yr)
Total					46,598.1

[1]Emission factors from AP-42, Section 1.4 (dated 3/98), Table 1.4-2, assume uncontrolled for N_2O, converted to lb/MMBtu by dividing by 1020 Btu/scf per footnote a.
[2]The increase in hourly fuel use is due to increased utilization of the process heaters and boilers as indicated in the D133 and wash water drum project (No. 3 crude unit) application (submitted on 4/5/11). Annual fuel use = 89.86 MMBtu/hr x 8760 hrs/yr.
[3]From Table A-1 of 40 CFR Part 98, Subpart A.
[4]VOC emissions estimated for this project are based on non-methane organic compounds. TOC emissions were determined by dividing estimated VOC emissions by 0.9. Methane emissions were estimated by subtracting VOC emissions from TOC emissions. Methane = (4.5/0.9) – 4.5 = 0.5 tpy.

This analysis indicates that PSD review is not triggered for GHG emissions.

2. Other Modifications

In addition to the requested modifications made by the source, the Division used this opportunity to include changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this modification.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments on other permits, to the Suncor Plants 1 and 3 (West Plant) Operating Permit with the source's requested modifications. These changes are as follows:

Section I – General Activities and Summary

- The language in Conditions 1.1 (one sentence) and 1.2 have been combined and the entire descriptive language is designated as Condition 1.1. In addition, additional descriptive language was added to the permit. The language that was in Condition 1.2 was revised to reflect the change in attainment status for the area.

- Revised and moved the wording in Condition 1.4 regarding applicable requirements from the Consent Decree and Compliance Order on Consent. In addition, the list of construction permits was revised to correct construction permit numbers and/or include construction permit numbers that had inadvertently not been included in the list. Also removed permit numbers 90AD502 (this permit addressed tank T-52 but permit was cancelled), C-10,998 (replaced by construction permit 04AD0111) 87AD180-3 (replaced by construction permit 04AD0111) and 91AD320 (tanks T20 & T21 were removed).

- Added Section IV, Conditions 3.g (last paragraph) and 3.d as state-only conditions to Condition 1.5. Note that Section IV, Condition 3.d (affirmative defense provisions for excess emissions during malfunctions) is state-only until approved by EPA in the SIP. In addition, Condition 36.2 was removed (Reg 6, Part B PM limits) as this condition was included in the permit shield for streamlined conditions (Section III.3 of the permit).

- The following changes were made to the table in Condition 5.1.
  - o Added a column to the Table in Condition 5.1 for the startup date of the equipment.
  - o Removed the list of components from F102 and F103. The number of components was not intended to serve as a permit limitation.
  - o Some of the tank descriptions were revised to reflect contents or type of tank for those situations where the information had not been included in the table or where the information may not have been correct.
  - o In the "description column" the tank number was removed as this is included in the column labeled "emission unit number". Also removed "one" from the description since the emission unit number clearly identifies one tank (one unit id number).

<u>Section II - General</u>

General

- Minor language and format changes were made to a number of permit conditions (both in the table and text) in order to more clearly indicate the monitoring or underlying requirement.

- In general permit conditions requiring emission calculations and/or recording throughputs specify that records shall be retained and made available to the Division upon request. In general many of this language has been removed since the general conditions require that records of all required monitoring and support information be retained for 5 years (general conditions 22.c and d), therefore, it is not necessary to explicitly state that records must be retained for all required monitoring.

- There are several conditions where the permit requires the source to calculate emissions monthly and keep a rolling twelve month total to monitor compliance with the annual emission limitations. However, the permit condition also includes a requirement to calculate emissions annually for purposes of APEN reporting and fees. It is not necessary to conduct a separate annual calculation of emissions for purposes of APEN reporting. The twelve month rolling totals of emissions is sufficient. Calendar year annual emissions are used in APEN reporting, this can be determined from the rolling twelve month totals. Therefore the paragraph relating to the annual emission calculation has been removed. In addition, annually has been removed from the table under the column labeled "monitoring interval".

- There are several cases where the summary table indicates that emissions shall be calculated monthly but the text of the specific permit condition specifies an annual emission calculation. In this case the summary table was revised to specify that frequency of emission calculations is annually.

- References to calculating emissions in accordance with the SO_2 Compliance Plan have been revised in the table and text to indicate that emissions will be calculated in accordance with Appendix H.

- For many monitoring requirements (e.g. calculating emissions), Reg 3, Part C, Section V.C.5 and 6 has frequently been cited. In general the Division has not included regulatory cites for requirements that are included as "periodic monitoring". Therefore, those citations noting Reg 3, Part C, Section V.C.5 and 6 have been removed.

NSPS Subpart J Requirements

- Revised the column in the table for the NSPS J fuel burning equipment to indicate that that a "continuous monitoring system" is used, rather than a "continuous emission monitor".

- The Consent Decree was cited for the NSPS Subpart J requirements for those heaters that would not otherwise be subject to NSPS J (i.e. commenced construction prior to the NSPS J applicability date (June 11, 1973)).

- The fuel gas requirements (limits on H_2S) were clearly indicated in the tables as NSPS J requirements.

Process Heaters, Boilers and Flares

- Included the source of the emission factors in the text portion of the permit.

- For units with fuel limits in units of Btu/year, the emission factors were converted to units of lb/MMBtu.

- The language in the permit specifying that "calculation of emissions shall be based on the Btu and sulfur analyses for the period of interest" was removed. Appendix H of the permit indicates how SO_2 emissions will be determined. In addition, since the emission factors were converted to lb/MMBtu this language was no longer necessary. Note that for the heaters and boilers without annual emission limitations, the language in the permit indicates that the appropriate Btu content for the period of interest shall be used in the emission calculations.

- The requirements for recording the fuel consumption is specified in Section II, Condition 59, which requires daily recording of fuel consumption for all sources except heaters H-16 and H-18. The summary tables for fuel consumption for these sources list recording frequency as monthly. Since daily recording is required the summary tables have been revised to specify daily, as well as the longer time period for emission calculations (monthly if fuel/emission limits and annual if no fuel/emission limits).

- The footnote regarding the AP-42 emission factors and Btu correction was included in the relevant summary table.

- The Reg 6, Part B, Section II requirements (PM and opacity) were applied to a number of heaters and/or boilers that were not subject to them (i.e. the units were constructed prior to January 30, 1979). Therefore, the Reg 6, Part B requirements were removed for these heaters and/or boilers.

- All of the heaters and boilers without annual emission limitations were grouped together under Section II.9 and this section was re-titled as "process heaters and boilers without annual emission limitations". This section includes H-10,H-11, H-16, H-18, H-22, H27 and B4. <u>This caused the renumbering of permit condition numbers for equipment that followed these heaters.</u>

- Heaters H-13 and H-17 were grouped together in Section II.16, since these units both have annual emission limitations and rely on the same emission factors. . <u>This caused the renumbering of permit condition numbers for equipment that followed these heaters.</u>

H-10, H-11, H-27 and B4

- Construction permit 95AD053 was issued for these units to make emission reductions to a fuel switch enforceable. The permit included limitations on the sulfur content of the fuel and required that revised APENs be filed as required by Reg 3 and that records of annual fuel use be retained. Citations to the permit for the APEN reporting and maintaining records of annual fuel use were removed from the permit, since these are not substantive requirements.

H-31 and H32

- Corrected the PM, PM_{10} and CO emission factors. The emission factors for PM, PM_{10} and CO do not match those used in the construction permit.

Tanks

- For tanks, the permit specifies that the most recent version of EPA Tanks be used to calculate emissions but allows the source as an alternate to use AP-42. The Division considers that the permit should only include one means to calculate emissions and has revised the permit to require use of EPA Tanks as this is the method the source is currently using.

- For tanks with throughput limits that include language such as "throughput of gasoline and/or lower vapor pressure material" the relevant vapor pressure has been included, if it can be determined. The Division has requested that Suncor provide the relevant information in those cases where the Division could not determined the appropriate vapor pressure. In addition, where the vapor pressure was listed in the current permit, the Division included the relevant units.

- In order for the tank throughput requirements to be listed more consistently throughout the permit the various permit conditions have been revised such that the language in the table lists the primary material(s), e.g. "gasoline" and the text contains the full language, e.g. "gasoline and/or materials with a RVP of 15 psia or less".

Flares

- The tables list PM and PM_{10} and imply that annual emissions of these pollutants are to be calculated; however, no emission factors are included. Since these are smokeless flares and PM and PM_{10} emissions are expected to be negligible, PM and PM_{10} have been removed from the table.

NSPS General Provisions

- The NSPS general provisions were not specifically noted in the tables or text for the individual emission units and Condition 57 (NSPS general provisions) merely stated that the requirements applied to those emission units subject to Reg 6, Part B or NSPS requirements. The tables and text for individual emission units subject to an NSPS were revised to indicate that the NSPS general provisions also apply.

Regulation No. 6, Part B, Section II – Particulate Matter Standards and General Provisions

Many of the heaters are subject to the Regulation No. 6, Part B, Section II requirements for particulate matter (lb/MMBtu standards and opacity), as well as the NSPS general provisions (on a state-only basis). Given that the limitations are similar, a streamlining analysis was done to see if any requirements could be streamlined in favor of more stringent requirements. The streamlining analysis is as follows:

Opacity

Many of the heaters are subject to the Regulation No. 1 opacity standards and the Regulation No. 6, Part B opacity requirement. The Reg 1 20% opacity requirement applies at all times, except for certain specific operating conditions under which the Reg 1 30% opacity requirement applies. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. 40 CFR Part 60 Subpart A § 60.11(c) specifies that the opacity requirements are not applicable during periods of startup, shutdown and malfunction. The Reg 1 20%/30% opacity requirements are more stringent than the Reg 6 Part B opacity requirements during periods of startup, shutdown and malfunction. While the Reg 6, Part B 20% opacity requirement is more stringent during fire building, cleaning of fire boxes, soot blowing, process modifications and adjustment or occasional cleaning of control equipment. Therefore, since no one opacity requirement is more stringent than the other at all times, all applicable opacity requirements are included in the operating permit. See the attached grid (page 87) for a clarified view on the opacity requirements and their relative stringency.

PM

Many of the heaters are subject to the Regulation No. 1 and No. 6, Part B PM standards. The PM requirements in both Reg 1 and Reg 6, Part B are the same standard. The Regulation No. 6, Part B requirement is a state-only requirement. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. Although not specifically stated in the general provisions, the Division has concluded after reviewing EPA determinations that the NSPS standards are not applicable during startup, shutdown and malfunction, unless indicated otherwise in the specific subpart, although any excess emissions during these periods must be reported in the excess emission reports. Specifically, EPA has indicated (4/18/75, determination control no. A007) that when 40 CFR Part 60 Subpart A § 60.11(d) was developed "…it was recognized that sources which ordinarily comply with the standards may during periods of startup, shutdown and malfunction unavoidably release pollutants in excess of the standards." In addition, EPA has also indicated (5/15/74, determination control number D034) that "[s]ection 60.11(a) makes it clear that the data obtained from these reports are not used in determining violations of the emission standards. Our purpose in requiring the submittal of excess emissions is to determine whether affected facilities are being operated and maintained 'in a manner consistent with good air pollution control practices for minimizing emissions' as required by 60.11(d)." Therefore, the Division considers that the Reg 6, Part B PM requirements do not apply during periods of startup, shutdown and malfunction. Therefore, the Regulation No. 1 PM requirement is more stringent than the Regulation No. 6, Part B requirement and the Regulation No. 6, Part B requirement will be streamlined out of the permit.

NSPS general provisions

Many of the heaters and boilers are subject to the NSPS general provisions (40 CFR Part 60) on a federal and state basis (the units are subject to 40 CFR Part 60 Subpart J) and on a state-only basis (the units are subject to Reg 6, Part B, Section II and the NSPS general provisions are adopted by reference in Reg 6, Part B, Section I.A). Therefore, the Division will streamline the state-only NSPS general provisions out of the permit in favor of the state and federal NSPS general provisions.

Based on the above analysis, the following revisions were made to the permit:

- Removed Condition 36.2 from Section I, Condition 1.3.

- The references to the Reg 6, Part B particulate matter requirements (Condition 36.2) were removed from the tables and text for the individual emission units.

- Section II, Condition 36.2 was removed (this includes the NSPS general provisions language included in this condition).

- Revised Section II, Condition 57 to remove the sentence regarding Reg 6, Part B and state-only requirements was removed from Condition 57.

- The Reg 6, Part B PM limitations (Section II.C.2) and the general provisions (Section I.B) were included in Section III.3 of the permit (permit shield for streamlined conditions)

<u>Tanks T52</u>

- In the April 4, 2006 revised permit tank T52 was moved to the insignificant activity list and as such it was removed from the table in Section I, Condition 5.1 (the use for T52 changed from storing naphtha to storing sour water with a layer of diesel to prevent volatilization of H_2S). However, references to T52 were not removed in other portions of the permit. The Division removed references to T52 from Section II, Conditions 41.2.3, 48 and 54.10. Note that although the source requested the re-permitting of tank T-52 the provisions in Condition 48 and 54.10 no longer apply to T52 and only the recordkeeping provisions in Condition 41.2.3 apply, so removal of references to T52 were still necessary.

<u>Section II.1 – Tanks with no permitted emission limitations</u>

- Removed “External Floating Roof” from the table header as not all the tanks in this section are EFRs.

<u>Section II.2 – Tank T1</u>

- Removed the NSPS Subpart K requirements (Condition 2.4). As indicated in 40 CFR Part 63 Subpart CC § 63.640(n)(5), tanks that are subject to NSPS Subpart K or Ka are only required to comply with the requirements in 40 CFR Part 63 Subpart CC.

<u>Section II.3 – Tanks subject to NSPS Kb and MACT CC</u>

- Removed permit number 90AD502 from the list in Condition 3.1, as this tank (T-52) was removed and the construction permit cancelled. Note that although the source requested the re-permitting of T52, a new AIRs id was assigned for this tank and permit 90AD502 was not re-instated.

- Removed the parenthetical language in Condition 3.10 for tank T34 regarding the true vapor pressure. The maximum true vapor pressure requirement is from NSPS Kb and is addressed in Conditions 3.8 and 48. Since Condition 3.10 relates to the annual emission limitations only, NSPS Kb related requirements have been removed from this condition. Note that the NSPS Kb requirements still apply.

- Added 40 CFR Part 61 Subpart FF (BWON) requirements for tank T-4501.

Section II.12 – Heater H-27

- Removed the sulfur limitation in Condition 12.5. This limit only applies until the provisions of NSPS Subpart J apply. Since the provisions of NSPS Subpart J apply December 31, 2006, these sulfur limits no longer apply and have been removed from the permit. Note that the sulfur limit in this condition (from CP 90AD053) has been included in Section II.3 of the permit (permit shield for streamlined conditions).

Section II.14 – Boiler B6

- Removed Boiler MACT initial notification requirement (Condition 14.9). The initial notification has been submitted and as discussed above under "Source Requested Modifications – January 12, 2007 Significant Modifications", the Boiler MACT was vacated and has been re-promulgated. This condition has been replaced with the appropriate MACT requirements.

Section II.19 – Heaters H-28, H-29 & H-30 and CRU

- Revised Condition 19.1 to indicate that the emission limitations apply to the heaters.

- Revised Condition 19.7 to indicate that the MACT requirements apply to the reformer.

Section II.20 & 21 – Heaters H-31 & H-32 and H-33 & H-37

- Removed the word "heaters" before the VOC emission factors in the Summary Tables. Since these sections only address heaters, it is not necessary to qualify that the emission factor is for the heaters.

Section II.22 – Emission reductions from heaters and boilers

- Removed Conditions 22.2.1, 22.1.3, 22.1.9, 22.1.10 and 22.2.3. Note that except for Condition 22.2.3, the source had proposed revisions to the language in the August 1, 2008 renewal application. These requirements (emission limitations and CEMS requirements) are addressed in the specific sections for Boilers B-6 and B-8.

- Revised the title for this section and re-numbered the Conditions.

Section II.23 – SRU No. 1

- Renumbered permit conditions so that the numbers in the table are more sequential.

- Included the Consent Decree requirements for Tail Gas Incidents.

Section II.25 - FCCU

- Removed the process weight rate particulate matter emission limitations (Condition 25.3). Since these requirements are based on a tons/yr processing rate, it appears that they were not intended to apply to equipment processing a liquid feed. The Division may have considered that these requirements applied primarily because the FCCU is a source of PM emissions and at the time of initial Title V permit issuance it was not subject to other PM emission limitations. However, the FCCU is currently subject to the NSPS Subpart J PM limitations.

- The following revisions to Consent Decree requirements were made:

    - Conditions 25.6, 25.10 and 25.11 were removed because they have been completed.
    - The following conditions were combined into one condition: Conditions 25.9 and 25.7 (NO_X requirements), Conditions 25.12 and 25.14 (SO_2 requirements) and Conditions 25.8 and 25.13 (hydrotreater outages).
    - Removed the summary statement from Condition 25.15 and revised the language in Condition 25.15.1 (mainly to remove the date).
    - Removed the dates from several conditions and made some small language changes to conditions within Condition 25.16, removed Condition 25.16.1 (it's a summary statement in the Consent Decree), and combined Conditions 25.16.4 and 25.16.6.

- Renumbered permit conditions so that the numbers in the table are more sequential.

Section II.26 – API Separator

- The API Separators addressed in this section have been removed and replaced. An APEN cancellaiont form was submitted on January 30, 2012 via e-mail. Provisions for the Plant 1 wastewater treatment system (which includes the new API separators) are included in "new" Section II.23 (this section previously included the No. 1 SRU).

Sections II.27 and 28 – Rail Rack and Truck Rack

- Included the appropriate emission factors in the table and included equations specifying how emissions are to be calculated.

Section II.29 – Groundwater Treatment Unit with Air Stripper

- The Division in general only allows one method for calculating emissions and assessing compliance with emission limitations, therefore, the language in Condition 29.1 was revised to require that emissions be calculated based on the inlet and outlet concentration. If the source chooses to rely strictly on the inlet concentration (assuming all VOCs evaporate), the Division will revise the permit to allow this option. In addition, the Division has revised the requirement to calculate emissions monthly. Given that the frequency of monitoring the contaminant concentration has been revised from daily to monthly, it seems more appropriate to require monthly emission calculations.

- The requirements in Condition 29.1 and 29.3 have been moved, to be more in line with the requirements specified in the summary table.

- Revised the monitoring requirements under Condition 29.4 (opacity) in the summary table. The summary table implies daily visible observations, which is not consistent with what is required in Condition 29.4.

- Removed the Reg 6, Part B 20% opacity requirements from Condition 29.4. The Reg 6 opacity requirements apply to fuel burning equipment and the air stripper is not fuel burning equipment.

<u>Section II.31 – Main Plant Flare</u>

- The language in Condition 31.2 (NSPS J requirements) was revised. The language in Condition 31.2 is found in the December 17, 2001 Compliance Order on Consent (COC) but this COC did not apply to the main plant flare. The main plant flare in subject to the requirements in NSPS Subpart J via the federal Consent Decree (H-01-4430).

- The language in Condition 31.2 was revised to indicate how the flare was complying with the NSPS requirements (the Consent Decree provided three options). In addition, the language in this condition was revised to include provisions for Hydrocarbon and Acid Gas Flaring (Root Cause Failure Analysis and Corrective Action requirements). These requirements are applicable to compliance method chosen by the source.

- Added a new condition to indicate that the NSPS Subpart A flare requirements (Condition 58) apply to this unit.

- Revised the RACT requirements (Condition 31.4) to include the requirements in Colorado Regulation No. 7, Section VIII.B.3.

<u>Section II.32 – Asphalt Unit Flare</u>

- Revised the language in Condition 32.2 to be consistent with the language in Condition 31.2, since this flare is also subject to the federal Consent Decree. Note that since this flare was subject to the December 17, 2001 COC, which is virtually the same as the Consent Decree requirement, the COC requirement is included in the permit shield for streamlined conditions (Section III.3).

- The language in Condition 31.2 was revised to indicate how the flare was complying with the NSPS requirements (the Consent Decree provided three options). In addition, the language in this condition was revised to include provisions for Hydrocarbon and Acid Gas Flaring (Root Cause Failure Analysis and Corrective Action requirements). These requirements are applicable to compliance method chosen by the source.

- Added a new condition to indicate that the NSPS Subpart A flare requirements (Condition 58) apply to this unit.

- Revised the RACT requirements (Condition 32.4) to include the requirements in Colorado Regulation No. 7, Section VIII.B.3.

Section II.33 – Asphalt Unit Sewer System

- References to the Asphalt Unit Sewer System have been revised to “Asphalt Unit (Plant 3) Wastewater Treatment System”.

- Removed the specific sections of 40 CFR Part 61 Subpart FF referenced in Condition 33.5, since the provisions in Subpart FF have been included in the permit as Condition 66. Note that although the Subpart FF requirements apply to the entire refinery, only that equipment that is subject to the control requirements in Subpart FF are noted as being subject to Subpart FF in their unit specific summary tables.

- This condition was revised to address only the CPI separator. The drains will be addressed in Section II.34 (fugitive VOC leak equipment) since drains subject to NSPS Subpart QQQ are addressed in this section.

- The current permit includes no monitoring requirements for the carbon filter on the CPI separator. The Division has included a requirement to monitor for breakthrough on the carbon filter once every 14 days.

Section II.34 – Fugitive VOC Leak Equipment with Permitted Emission Limits

- Language was added to identify the methodology used to calculate emissions.

Section II.35 – Opacity Limits

- Revised the column labeled “monitoring – method and interval” in the summary table for the Reg 1 20%/30% and Reg 6, part B 20% opacity requirements to specify that specific monitoring is based on emission unit and refer to specific condition numbers.

- Revised the monitoring language in Conditions 35.5 through 35.6 to indicate to which of the specific opacity requirements the monitoring language applies to.

- Minor changes to the opacity monitoring language was made to Condition 35.7.

- The opacity monitoring requirements in Condition 35.8 have been revised to refer to Condition 58. The monitoring included in existing Condition 35.8 relies on Method 22 observations which are not appropriate for the opacity standards included in Condition 35 (these opacity standards rely on Method 9 observations). The monitoring in Condition 58 is appropriate for flares subject to visible emission requirements in 40 CFR Part 60 § 60.18. This also results in consistent monitoring requirements for all flares.

- Removed the general provisions language from Condition 35.4, except for the 60.11(c) requirements since the general provisions language is in Condition 57.

- Based on EPA's response to a petition on another Title V operating permit, minor language changes were made to Condition 35.5 to clarify that only gaseous fuel is permitted to be used as fuel in the fuel burning equipment and included a requirement to maintain records indicating that only gaseous fuel is used.

Section II.36 – PM Limits – Fuel Burning Equipment

- Based on EPA's response to a petition on another Title V operating permit, minor language changes were made to Condition 36.1 to clarify that only gaseous fuel is permitted to be used as fuel in the fuel burning equipment and included a requirement to maintain records indicating that only gaseous fuel is used.

Section II.37 – PM Limits – Manufacturing Processes

- This condition (the Reg 1 process weight rate PM limits) was removed from the permit. Upon further review, since the process weight rate limits are determined based on the processing rate, in tons/hr, that such limits were not intended to apply to manufacturing processes that process liquid feed. Note that requirements for the soil vapor extraction engine are included in Section II.37.

Section II.38 – SO_2 Limits

- Removed the requirement to submit a revised SO_2 compliance plan in Condition 38.3, since the source has submitted a revised plan and the Division has approved the plan (the plan has been included in Appendix H of the permit). In order to preserve the numbering, condition 38.3 has been identified as "reserved".

- Condition 38.2 was revised to address only the requirements for fuel gas combustion devices. The SRU requirements (Condition 38.2.2) are also included 45 so they will not be included in this Condition 38.

- More detailed info was added to Condition 38.2 and sub-conditions were assigned condition numbers. In addition, the language regarding the SO_2 CEMS option was not included, since the source has not chosen that option.

Section II.40 – RACT – Reg 7, Section IV

- Condition 40.2 was revised to require semi-annual monitoring for these tanks. This is consistent with the monitoring required under Condition 39.1.

Section II.41 – RACT – Reg 7, Section VI

- Removed the statement indicating that a copy of the complete regulation is attached and is federally and state enforceable. A copy of the regulation is not attached to the permit.

- Removed the statement from Condition 41.2.3 that this condition continues to apply to attainment/maintenance areas. The area was re-designated as nonattainment for ozone on November 21, 2007.

- The language in Condition 41.4.1 regarding operating procedures is not relevant to the requirements in this condition, therefore, the paragraph has been moved to Condition 41.5.1. The language in Condition 41.5.1 regarding inspections has been removed.

Section II.43 – RACT – Reg 7, Section VIII

- Added language to Condition 43.3 to indicate that flares that meet the requirements in 40 CFR Part 60 § 60.18 comply with are in compliance with the requirements in Reg 7, Section VIII.B.3 (Condition 43.3).

Section II.45 – 40 CFR Part 60 Subpart J

- In general, all substantive paragraphs have been assigned condition numbers.

- Removed the paragraph in Condition 45.3 under “performance test and compliance provisions” that addresses complying with 60.104(b)(3), since that compliance option was not chosen.

- Removed Condition 45.5 (refers to NSPS general provisions in Condition 57) since references to the NSPS general provisions are included in the sections for the individual emission units (e.g. Section II.20).

- The summary table for the FCCU indicates annual stack tests are required to monitor compliance with the PM emission limitation. However, the text portion in Section II.45 doesn’t address the stack test frequency requirement (the NSPS only requires an initial performance test), so the Consent Decree requirement for annual stack testing was included in this Condition.

- Added the NSPS Subpart J test method and procedures requirements for the chosen SO_2 option in the permit (§§ 60.106(g) and (i)). Although the FCCU is equipped with a CEMS, this is not the compliance method specified in the NSPS and it is not clear is an alternative monitoring method has been approved under 60.106(i)(12).

<u>Section II.46 – Subpart J and Flaring</u>

- This condition (Subpart J and Flaring) was removed as these requirements have either been completed or are included in the section for the specific emissions unit. Note that Condition 46.2.6 was included in the permit shield for streamlined conditions (Section I, Condition 1.3). With recent revisions to NSPS J, the sulfur monitoring requirements are not required for equipment that burns fuel gas streams that are inherently low in sulfur. Such a demonstration has been made for the rail rack flare. Note that the NSPS Subpart Ja requirements have been included in Section II.46.

<u>Section II.47 – 40 CFR Part 60 Subpart K</u>

- This condition (NSPS Subpart K) was removed and the NSPS Subpart K requirements have been listed in the permit shield for streamlined requirements (Section III.3 of the permit). As indicated in 40 CFR Part 63 Subpart CC § 63.640(n)(5), Group 1 storage vessels that are also subject to the requirements in NSPS Subpart K or Ka are only required to comply with the requirements in 40 CFR Part 63 Subpart CC. Note that NSPS Subpart GGGa requirements have been included in Section II.47.

<u>Section II.48 – 40 CFR Part 60 Subpart Kb</u>

- Condition numbers 48.1.1 through 48.1.3 were renumbered to a higher style level (e.g. 48.1.1 was renumbered as 48.2). In general all substantive paragraphs were assigned condition numbers.

- Removed Condition 48.3.1 (closed vent system and flare) since these requirements only applied to T20 and T21 which have been removed from the facility.

- Removed language stating that a complete copy of the regulation was attached.

- Removed Condition 48.2 (refers to NSPS general provisions in Condition 57) since references to the NSPS general provisions are included in the sections for the individual emission units (e.g. Section II.3).

<u>Section II.49 – 40 CFR Part 60 Subpart UU</u>

- In general, all substantive paragraphs were assigned condition numbers.

Section II.50 – 40 CFR Part 60 Subpart XX

- Removed Condition 50, since it does not apply.

Section II.51 – 40 CFR Part 60 Subpart GGG

- Removed language stating that a complete copy of the regulation was attached.
- Removed Condition 51.3 (refers to NSPS general provisions in Condition 57) since references to the NSPS general provisions are included in the sections for the individual emission units (e.g. Section II.34).
- In general, all substantive paragraphs were assigned condition numbers.
- Revisions were to include the exceptions and more appropriately address other requirements.

Section II.52 – 40 CFR Part 60 Subpart QQQ

- Removed Condition 52.3 (refers to NSPS general provisions in Condition 57) since references to the NSPS general provisions are included in the sections for the individual emission units (e.g. Section II.34).
- In general, all substantive paragraphs were assigned condition numbers.
- Added language indicating that in accordance with 40 CFR Part 63 Subpart CC § 63.640(o)(1) that group 1 wastewater streams that are managed in a piece os equipment that is subject to Subpart QQQ only have to meet the requirements in Subpart CC.
- Conditions 52.16 (applies separators with a design capacity of more than 250 gpm) and 52.17 (applies to modified or reconstructed separators) were removed since they do not apply. According to information in the Division's files, the CPI separator was designed to a capacity of 200 gpm and the CPI separator is a new unit.

Section II.53 – 40 CFR Part 63 Subpart R

- Moved the language indicating that the source is subject to the latest version of these requirements to the beginning of the section. In addition removed the statement that the requirements are state and federally enforceable, as this statement is unnecessary. Unless the requirements are specifically designated as state-only or federal-only, they are state and federally enforceable.
- Added some additional requirements under Condition 53.5.
- Indentified specific requirements from the general provisions in Condition 53.2.

- In general, all substantive paragraphs were assigned condition numbers.

Section II.54 – 40 CFR Part 63 Subpart CC

- Corrected the statement at the beginning of this section indicating what facilities are affected by this subpart, as the current reference to Subpart R is not relevant.

- Moved the language indicating that the source is subject to the latest version of these requirements to the beginning of the section. In addition removed the statement that the requirements are state and federally enforceable, as this statement in unnecessary. Unless the requirements are specifically designated as state-only or federal-only, they are state and federally enforceable.

- In general, all substantive paragraphs were assigned condition numbers. In addition some conditions were renumbered (i.e. conditions 54.1 through 54.7 were numbered at a lower level (54.1 is renumbered as 54.1.1).

- The general provision conditions (Conditions 54.1 through 54.7) were revised to cite requirements rather than included the full language of the requirement.

- Added some additional requirements to this section regarding storage tanks. In addition, the list of storage tanks not subject to these requirements was corrected and a list of Group 1 tanks was included.

- Since many of the exceptions to the Subpart VV requirements (equipment leaks – condition 54.17) do not apply, the language regarding equipment leaks has been revised.

- The language regarding heat exchange systems was included in the permit. Provisions for heat exchange systems were addressed in October 28, 2009 revisions to MACT CC. Note that EPA has proposed revisions to these requirements for heat exchange systems and the Division has added a note indicating that these requirements may change.

- With respect to recordkeeping and reporting requirements, the recordkeeping and reporting requirements have been moved to 63.655 with the addition of the requirements for heat exchange systems, so the citations were revised as appropriate. In addition, the following paragraphs were removed as they do not apply or have been completed:

    - Paragraph related to requesting approval of use alternative to the continuous operating parameter
    - The provisions in paragraph 63.654(h)(6)

Section II.55 – 40 CFR Part 63 Subpart UUU

- Moved the language indicating that the source is subject to the latest version of these requirements to the beginning of the section. In addition removed the statement that the requirements are state and federally enforceable, as this statement is unnecessary. Unless the requirements are specifically designated as state-only or federal-only, they are state and federally enforceable.

- Based on revisions to the requirements in 40 CFR Part 63 Subpart UUU that were published in the April 20, 2006 Federal Register, the language in Conditions 55.82 and 55.85 were revised and Condition 55.83 was removed.

- Indentified specific requirements from the general provisions in Condition 55.128.

Section II.56 – Equipment Leak VOC Emissions

- Due to consolidation of many permit exempt heaters into one section, the provisions of Equipment Leak VOC Emissions were moved to "new" Condition 33 (Note that in the current permit Section II.33 addresses the Asphalt Unit Sewer System). Note that the NSPS Subpart VVa requirements are now included in Section II.56.

- Added a summary table for this section addressing applicable requirements. These include emission calculations, RACT, MACT and potentially NSPS requirements. The current permit only addressed calculating emissions. The language regarding the emission calculations was revised to specify the methodology used to calculate emissions.

Section II.58 – 40 CFR Part 60 Subpart A

- The language in Condition 58.9 was revised to specify that if after performing corrective action, a 2 hour method 22 shall be performed to assess compliance with the specific visible emissions requirements. Given that the visible emission requirement standard is based on a 2 hour period, a 6 minute Method 22 is insufficient to monitor compliance with the visible emissions requirement.

Section II.59 (Fuel Monitoring)

- Revised the fuel monitoring language to address natural gas (city gas). The heat content of natural gas is determined monthly using vendor receipts.

Section II.60 – Continuous Emissions Monitors (Consent Decree)

- Condition 60.2 (upgrading existing CEMS) was removed since the requirement has been completed.

Section II.61 – Permitting (Consent Decree)

- This Condition has been removed since the requirements have been completed. Note that requirements related to facility access are now included in Section

II.61.

Section II.62 – Consent Decree General Recordkeeping, Record Retention and Reporting

- Revised the language in various conditions in this section to address changes made in the second amendment to the Consent Decree (reporting frequency changed from quarterly to semi-annual).

Section II.63 – Emission Factors

- Revised the language in this condition to make it clear that a permit revision is not necessary to revise emission factors used only for APEN reporting purposes.

Section III- Permit Shield

- Removed the fuel sulfur limit from construction permit 90AD053 from the permit shield for non-applicable requirements (Section III.1). The fuel sulfur limit is an applicable requirement but it is less stringent than another applicable requirement; therefore, the requirement is more appropriately addressed in the permit shield for streamlined conditions (Section III.3). In addition, the streamlined fuel sulfur limit from construction permit 90AD053 no longer applies to boilers B-6 and B-8, since they are no longer covered under construction permit 90AD053 (construction permits 02AD0326 and 02AD0327) were issued for these boilers

- NSPS Ka was removed from the shield for non-applicable requirements (Section III.1). The shield applies facility wide and the justification provided in the permit is based on the applicability date, however, the Division does not have sufficient information to support this justification.

- The table in Section III.3 has been revised to be consistent with the way the table appears in other Title V permits.

- Removed the component count limits from the permit shield for streamlined requirements (Section III.3). The component count limits have been removed from the underlying construction permits. As provided for in Section I, Condition 1.3 of the permit, the underlying construction permits can be modified directly in the Title V permit.

- Removed the FCCU Reg 1, Section IX requirements from the shield for non-applicable requirements (Section III.1) and put it in the shield for streamlined conditions. The Reg 1 limit is still an applicable requirement, but since it is as stringent as the consent decree and NSPS CO limits, the permit shield is the more appropriate place for this requirement.

Section IV - General Conditions

- Included a version date.

- The upset requirements in the Common Provisions Regulation (general condition 3.d) were revised December 15, 2006 (effective March 7, 2007) and the revisions were included in the permit. Note that these provisions are state-only enforceable until approved by EPA into Colorado’s state implementation plan (SIP).

- Replaced the reference to “upset” in Condition 5 (emergency provisions) and 21 (prompt deviation reporting) with “malfunction”.

- The title for Condition 6 was changed from “Emission Standards for Asbestos” to “Emission Controls for Asbestos” and in the text the phrase “emission standards for asbestos” was changed to “asbestos control”.

- General Condition No. 21 (prompt deviation reporting) was revised to include the definition of prompt in 40 CFR Part 71.

- General Condition 29 was revised by reformatting and adding the provisions in Reg 7, Section III.C as paragraph e.

<u>Appendices</u>

- Replaced Appendices B and C with the latest versions.

- Revised Appendix D to revise the individual from the APCD who should receive the T5 reports.

- Added the SO_2 Emissions Calculation Methodology (appendix H) to the table of contents for the appendices.

- Cleared the modification information from the table in Appendix F (this table starts anew with the renewal).

- The following revisions were made to Appendix G:

    - Removed the second sentence in Appendix G stating that these requirements are not included in the Operating Permit. As specifically noted in Section II of the permit, the provisions in Appendix G are part of the Operating Permit and are state and federally enforceable under the Operating Permit provisions.

    - Revised language to indicate changes made with the second amendment to the Consent Decree (quarterly reporting frequency changes to semi-annual).

- Included the revised SO_2 Emissions Calculation Methodology document to Appendix H (replaces previous sulfur dioxide monitoring plan).

3. Changes Made to Draft Renewal Permit Based on Public Comments

Comments were received on the draft renewal permit on May 21, 2012 during the public comment period. The following changes were made to the permit based on those comments:

Section I - General Activities and Summary

- Condition 1.4 was revised to remove Section IV, Condition 3.d as a state-only requirement, since EPA approved these provisions into Colorado's SIP effective October 6, 2008.

Sections II.12 and 13 – Boilers B6 and B8

- Conditions 12. 8 and 13.8 were revised to require that permit applications be submitted within 30 days of EPA's approval of any alternative CO limits into the permit.

- Conditions 12.8 and 13.8 were revised to specify what information would be used to assess whether good air pollution control practices were used to minimize emissions.

Section II.20 – Sulfur Recovery Units and Tail Gas Incinerator

- Language was added to Condition 20.5 to indicate that the provisions specified in Condition 20.5 apply with respect to the emission limitations in Condition 20.6.

Section II.57 – NSPS General Provisions

- The first sentence in Condition 57 was revised to indicate the NSPS general provisions apply with respect to the NSPS requirements.

Section IV – General Conditions

- The paragraph in Condition 3.d indicating that the requirements are state-only has been removed, since EPA approved these provisions into Colorado's SIP effective October 6, 2008.

Suncor Plants 1 and 3 (West Plant) – Potential to Emit

Emission Unit	PM	$PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
Tanks						
T1						13.60
T2						3.70
T3						3.70
T34						14.00
T52						0.11
T55						13.52
T58						4.17
T62						0.09
T67						4.30
T70						6.10
T74						1.56
T75						6.40
T77						7.88
T78						2.08
T80						2.72
T94						1.48
T96* T97*						5.90
T116						7.10
T774						0.54
T775						7.10
T776						0.85
T777						2.75
T778						3.54
T2006						0.20
T2010						4.98
T3201						2.80
T3801						2.19
T4501						6.68
T7208						0.39
GW1 – GW8						1.16
Fired Sources						
H-6	0.47	0.47	1.65	3.06	5.14	0.34
H-10	1.11	1.11	3.89	14.61	12.27	0.80
H-11	0.97	0.97	3.40	12.78	10.73	0.80
H-13	0.22	0.22	0.87	2.89	2.43	0.16
H-16	0.20	0.20	0.69	2.58	2.16	0.14
H-17	1.89	1.89	7.45	24.83	20.86	1.37
H-18	0.20	0.20	0.69	2.58	2.16	0.14
H-19	0.96	0.96	3.44	15.34	10.54	0.69
H-20	0.46	0.46	1.60	6.01	5.05	0.33
H-22	1.95	1.95	6.63	25.66	21.56	1.41
H-27	2.50	2.50	8.74	32.84	27.59	1.81
H-28,29,30	3.10	3.10	10.50	20.40	34.20	2.20
H-31* H-32*	3.68	3.68	7.66	32.25	16.39	0.89
H-33* H-37*	2.10	2.10	8.28	26.30	23.19	1.52
H-1716* H-1717*	3.15	3.15	10.30	12.70	16.92	2.28
H-2101	10.80	10.80	10.20	52.19	57.99	7.74
H-2410	1.68	1.68	2.75	9.50	9.02	1.24
B-4	4.24	4.24	14.86	156.31	46.89	3.07
B-6	3.59	3.59	12.70	19.45	19.45	2.60
B-8	5.20	5.20	18.40	28.21	28.21	3.77

Emission Unit	PM	$PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
Process Units						
P101, P102 & H-25 - No. 1 and No. 2 SRUs with TGU and Incinerator (H-25)	0.48	0.48	59.70	1.97	2.63	0.35
P103 – FCCU						
F201 – Plant 1 Wastewater Treatment System						8.80
R101 - Rail Rack				1.97	10.72	7.01
R102 - Truck Rack				4.00	21.00	29.00
A1 - Air Strippers						9.90
F1 - Main Plant Flare			103.56	12.36	67.25	25.45
F2 - Asphalt Unit Flare			0.01	0.64	3.50	1.31
F3 – GBR Unit Flare			0.04	1.00	1.80	0.70
F101 - Asphalt Unit (Plant 3) Wastewater Treatment System						5.00
Centrifuge Generator Engine				4.06	3.55	1.32
Fugitive VOC Emission Sources						
F102 - Asphalt Processing Unit						8.13
F103 - No. 3 HDS						23.15
F104 - Cryogenic Vapor Recovery Unit						10.06
F105 - No. 2 HDS						1.81
F106 - LSR Distillate Tower						4.50
F107 - Plantwide Fugitive VOCs - Unpermitted						31.92
F108 - Vapor Recovery Unit Debutanizer						6.80
F109 - No. 4 HDS						9.68
F110 - TGU Amine System						1.27
F111 - Sour Water Stripper						0.12
F112 - Modified Tank Farm						5.27
F113 - No. 1 Catalytic Reforming Unit Modifications						4.50
F114 – GBR Unit Fugitive						9.24
F115 – Bio-Diesel Fugitive						3.38
Total	138.15	138.15	396.51	692.69	741.80	405.16

Notes:

*units have combined emission limits.

1. Tanks D-811, D-812, D-813, D-814, T81, T82, T90, T91, T92, & T400 not included. These tanks are pressurized tanks with no emissions.
2. Tanks T33, T57, T59, T64, T65, T66, T68, T69, T71, T72, T76, T105, T112, T140, T142, T144, T145, T146, T147, T182, T191, T192, T193 & T194 not included. These tanks have very low emissions. They would be insignificant activities except that they are subject to MACT CC requirements.
3. The catalytic reforming unit was not included. This unit is not a source of emissions. It has been included in the permit because it is subject to MACT UUU requirements.
4. The soil vapor extraction equipment was not included. The engine is not a stationary source (it's a non-road engine) and the thermal oxidizer has very low emissions. It would be an insignificant activity except that it is subject to NSPS J.
5. Potential to emit is based on the following:
   a. permitted emission limits.

b. For heaters and boilers without permit limits, the emission factors in the permit (AP-42, Section 1.4, dated 3/98), design rate of the unit (MMBtu/hr) and 8760 hrs/yr of operation.

c. For tanks T67, T70, T74, T75, T77, T78, T80 and T776 from the PTE indicated in the original T5 application (submitted 1/26/96).

d. For the Main Plant Flare PTE is based on the maximum annual emissions from the 2007 - 2009 data Suncor submitted for the regional haze SIP x 1.2. For SO_2 PTE is based on 2007 data, for other pollutants PTE is based on 2009 data. With the flare gas recovery system, emissions are generally from flaring pilot gas.

e. For the Asphalt Unit Flare PTE is based on the maximum actual annual emissions specified in the 2008 - 2010 inspection reports x 1.2. With the flare gas recovery system, emissions are consistent and are essentially from flaring pilot gas.

f. For the FCCU PTE is based on information provided by Suncor on October 14, 2011 to provide max flow rate, coke burn-off and feed rate. The PM, PM_{10} and VOC emission factors in T5 permit were used with max coke burn-off and feed rate. The annual CO, NO_X and SO_2 limits (ppm, 365-day average) were used with the max flow rate.

g. For plantwide fugitive VOCs, unpermitted (F107),PTE is based on 3 x 2009 actual emissions.

h. For the Plant 1 wastewater treatment system and Asphalt unit (Plant 3) wastewater treatment system, PTE is based on requested emissions in APEN submitted 2/27/12.

Suncor Plants 1 and 3 (West Plant) – Actual Emissions

Emission Unit	Data Year	PM	$PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
Tanks							
T1	2006						7.77
T2	2004						1.01
T3	2003						0.85
T34	2006						10.38
T52	PTE						0.11
T55	2009						1.66
T58	2005						0.62
T62	2003						0.05
T67	2007						2.78
T70	2003						3.40
T74	2003						0.40
T75	2009						3.19
T77	2006						4.50
T78	2006						11.01
T80	2005						8.09
T94	2003						1.20
T96	2003						3.20
T97	2003						1.80
T116	2003						0.15
T120	2003						0.00
T774	2006						0.13
T775	2003						3.40
T776	2005						2.38
T777	2006						0.08
T778	PTE						3.54
T2006	2003						0.05
T2010	2009						2.72
T3201	2005						0.09
T3801	PTE						2.19
T4501	2006						0.62
T7208	2003						0.01
Fired Sources							
H-6	2009	0.47	0.47	0.46	3.12	5.25	0.34
H-10	2007	0.60	0.60	0.07	7.96	6.68	0.44
H-11	2009	0.76	0.76	0.74	10.01	8.41	0.55
H-13	2009	0.14	0.14	0.14	1.82	1.53	0.10
H-16	2005	0.20	0.20	0.06	2.58	2.16	0.14
H-17	2009	1.08	1.08	0.97	14.15	11.89	0.78
H-18	2005	0.20	0.20	0.06	2.58	2.16	0.14
H-19	2007	0.17	0.17	0.02	2.77	1.90	0.12
H-20	2007	0.39	0.39	0.05	5.14	4.31	0.28
H-22	2009	0.06	0.06	0.01	0.81	0.68	0.04
H-27	2009	1.62	1.62	0.44	21.32	17.60	1.17
H-28,29,30	2009	1.66	1.66	1.47	10.90	18.32	1.20
H-31	2009	0.47	0.47	0.43	7.52	5.16	0.34
H-32	2006	0.26	0.26	0.07	4.19	2.88	0.19
H-33	2003	0.23	0.23	0.04	1.00	1.40	0.09
H-37	2009	1.39	1.39	1.26	22.33	15.32	1.00
H-1716	2009	1.15	1.15	1.08	4.66	6.21	0.82
H-1717	2009	0.57	0.57	0.55	2.31	3.07	0.41
H-2101	2009	5.73	5.73	0.57	40.39	2.92	4.10
B-4	2009	1.90	1.90	1.37	69.92	20.98	1.37
B-6	2009	2.38	2.38	2.26	12.06	1.82	1.72
B-8	2007	2.54	2.54	0.31	9.09	2.50	1.84

Emission Unit	Data Year	PM	$PM_{10}/PM_{2.5}$	SO_2	NO_X	CO	VOC
Process Units							
P101, P102 & H-25 - No. 1 and No. 2 SRUs with TGU and Incinerator (H-25)	2009	0.08	0.08	26.71	0.32	0.43	0.06
P103 – FCCU	2009	66.82	66.82	26.50	61.12	9.02	23.90
F201 - API Separator	2005						0.02
R101 - Rail Rack	2003				0.50	2.80	2.80
R102 - Truck Rack	2009				2.15	11.67	10.96
A1 - Air Strippers	2003						0.70
F1 - Main Plant Flare	2009			81.80	10.30	56.00	21.20
F2 - Asphalt Unit Flare	2007			0.01	0.53	2.05	1.09
F101 - Asphalt Unit Sewer System	2001						4.20
Fugitive VOC Emission Sources							
F102 - Asphalt Processing Unit	2009						2.46
F103 - No. 3 HDS	2009						3.29
F104 - Cryogenic Vapor Recovery Unit	2007						0.54
F105 - No. 2 HDS	2007						0.70
F106 - LSR Distillate Tower	2007						0.76
F107 - Plantwide Fugitive VOCs - Unpermitted	2009						10.64
F108 - Vapor Recovery Unit Debutanizer	2007						0.74
F109 - No. 4 HDS	2009						2.75
F110 - TGU Amine System	2007						0.19
F111 - Sour Water Stripper	2006						0.14
F112 - Modified Tank Farm	2006						0.48
F113 - No. 1 Catalytic Reforming Unit Modifications	PTE						2.50
Total		90.87	90.87	147.45	331.55	225.12	184.68

Notes:
1. Tanks D-811, D-812, D-813, D-814, T81, T82, T90, T91, T92, & T400 not included. These tanks are pressurized tanks with no emissions.
2. Tanks T33, T57, T59, T64, T65, T66, T68, T69, T71, T72, T76, T105, T112, T140, T142, T144, T145, T146, T147, T164, T169, T170, T171, T172, T182, T191, T192, T193 & T194 not included. These tanks have very low emissions. They would be insignificant activities except that they are subject to MACT CC requirements.
3. The catalytic reforming unit was not included. This unit is not a source of emissions. It has been included in the permit because it is subject to MACT UUU requirements.
4. The soil vapor extraction equipment was not included. The engine is not a stationary source (it's a non-road engine) and the thermal oxidizer has very low emissions. It would be an insignificant activity except that it is subject to NSPS J.
5. Except for the main plant flare, actual emissions are based on the most recent APENs on file that report actual emissions. Data year indicates year for which actual emissions are reported, if PTE is indicated in this field, emissions indicated are requested (i.e. permit limits). Emissions from the main plant flare are based on NO_X and SO_2 information submitted by Suncor for the regional haze SIP (CO and VOC emissions were estimated by the Division based on this data).

Opacity Streamlining Grid

Reqmt Source	Normal	Start-up	Shutdown	Malfunction	Fire Building	Cleaning of Fire Boxes	Soot Blowing	Process Modifications	Adjustment of Control Equipment
Reg 1 Sections II.A.1 & 4	20%	30% with one 6 minute interval in excess of 30% per hour	20%	20 %	30% with one 6 minute interval in excess of 30% per hour	30% with one 6 minute interval in excess of 30% per hour	30% with one 6 minute interval in excess of 30% per hour	30 % with one 6 minute interval in excess of 30% per hour	30% with one 6 minute interval in excess of 30% per hour
Reg 6, Part B, Section II.C.3 **- State Only**	20%	No standard[1]	No standard[1]	No standard[1]	**20%**	**20%**	**20%**	**20%**	**20%**

[1]Although the opacity standards are not applicable during start-up, shutdown and malfunction 40 CFR § 60.7(c) (2) requires the source to report each period of excess emissions that occurs during startups, shutdowns, and malfunctions, the nature of the malfunction and the corrective action taken or preventative measures adopted.

* Shaded regions are the most stringent **Federal** requirements

** Values in bold are the most stringent **State-only** requirements however **federal** requirements cannot be streamlined out of the permit due to more stringent **state-only** requirements